Regency Energy Partners LP
Form 10-K
March 31, 2006

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2005

OR

o 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: 0001-338613

REGENCY ENERGY PARTNERS LP

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	16-1731691 (I.R.S. Employer Identification No.)
1700 Pacific Avenue, Suite 2900 Dallas, Texas (Address of principal executive offices)	75201 (Zip Code)

(214) 750-1771
(Registrant s telephone number, including area code)
[None]
(Former name, former address and former fiscal year, if changed since last report)
Securities registered pursuant to Section 12(b) of the Act: None
Securities registered pursuant to Section 12(g) of the Act:

Title of each class	**Name of each exchange on which registered**
Common Units of Limited Partner Interests	Nasdaq National Market

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

Indicate by check mark if the registrant is required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes þ No o

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 o No þ

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. o

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

Large accelerated filer o Accelerated filer o Non-accelerated filer þ

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

As of March 15, 2006, the aggregate market value of the registrant s common stock held by non-affiliates of the registrant was $322,543,500 based on the closing sale price as reported on the National Association of Securities Dealers Automated Quotation System National Market System.

Indicate the number of outstanding units of each of the registrant s classes of units, as of the latest practicable date.

Class	**Outstanding at March 15, 2006**
Common Units	19,103,896
Subordinated Units	19,103,896

DOCUMENTS INCORPORATED BY REFERENCE

None.

REGENCY ENERGY PARTNERS LP
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PART I

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PART I

Introductory Statement

References in this report to Regency Energy Partners, we, our, us and similar terms, when used in an historical context, refer to Regency Energy Partners LP, or the Partnership, and to Regency Gas Services LLC, all the outstanding member interests in 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. References to our general partner or the General Partner refer to Regency GP LP, the general partner of the Partnership, and to the Managing GP refer to Regency GP LLC, the general partner of the General Partner, which effectively manages the business and affairs of the Partnership. References to HM Capital refer to HM Capital Partners LLC. References to HM Capital Investors refer to Regency Acquisition LP, HMTF Regency L.P., HM Capital and funds managed by HM Capital, including the Hicks, Muse, Tate & Furst Equity Fund V, L.P., and certain co-investors, including some of the directors and officers of the Managing GP. Regency Acquisition LP is wholly owned by HMTF Regency L.P., which, in turn, is wholly owned by HM Capital, funds managed by HM Capital and certain co-investors.

Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by us in periodic press releases and some oral statements of our officials during presentations about the Partnership, include certain 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. These forward-looking statements are identified as any statement that does not related strictly to historical or current facts. Statements using words such as anticipate, believe, intend, project, plan, expect, continue, estimate, goal, forecast, may, will, or simi identify forward-looking statements. Although we and our Managing GP believe such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, neither we nor our Managing GP can give assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. When considering forward-looking statements, please read the section titled Risk Factors included under Item 1A of this annual report.

ITEM 1. Business.

Overview

We are a Delaware limited partnership recently formed by HM Capital Partners LLC (formerly Hicks, Muse, Tate & Furst Incorporated), or HM Capital, to capitalize on opportunities in the midstream sector of the natural gas industry. We are a growth-oriented independent midstream energy partnership engaged in the gathering, processing, marketing and transportation of natural gas. We provide these services through systems located in north Louisiana, west Texas and the mid-continent region of the United States, which includes Kansas, Oklahoma, Colorado and the Texas Panhandle.

We divide our operations into two business segments:

Gathering and Processing: in which 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 natural gas liquids, or NGLs, from the raw natural gas and selling or delivering the pipeline-quality natural gas and NGLs to various markets and pipeline systems; and

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Transportation: in which we deliver natural gas from northwest Louisiana to northeast Louisiana through our 320-mile Regency Intrastate Pipeline system, which has been significantly expanded and extended through our Regency Intrastate Enhancement Project.

Please refer to Notes 8 and 9 of the consolidated financial statements for information regarding revenues from external customers, segment margin, and total assets by segment.

Gathering and Processing Segment

We operate our Gathering and Processing segment in three geographic areas of the United States: north Louisiana, west Texas and the mid-continent region. Our gathering and processing assets include five cryogenic processing plants, of which four are currently active, and approximately 2,950 miles of related gathering and pipeline infrastructure connected to approximately 2,650 active wells. In north Louisiana, we own a large gathering system that is connected to two processing plants that we own and operate. In west Texas, we own a large gathering system that is connected to a processing plant that we own and operate. In the mid-continent region, we own three large gathering systems, one of which is connected to a processing plant that we own and operate. Our Gathering and Processing segment also includes our NGL marketing business through which we sell the NGLs that are produced by our processing plants for our own account and for the accounts of our customers.

The following table contains information regarding our gathering systems and processing plants as of December 31, 2005:

Region	Asset Type	Length (Miles)	Wells Connected	Compression (Horsepower)	Throughput Capacity (MMcf/d)
North Louisiana	Gathering pipelines	600	700	14,500	300
	Processing facilities			10,000	90
West Texas	Gathering pipelines	750	450	22,000	200
	Processing facility			20,000	125
Mid-Continent	Gathering pipelines	1,600	1,500	41,500	265
	Processing facility			3,650	50(1)

(1) Excludes 80 MMcf/d of throughput capacity available at our inactive Lakin processing facility.

Transportation Segment

Our Transportation segment consists of our Regency Intrastate Pipeline system, a 320-mile natural gas pipeline in north Louisiana that transports natural gas primarily from northwest Louisiana to northeast Louisiana where it connects to a number of interstate and intrastate pipelines. Upon completion of our Regency Intrastate Enhancement Project in December 2005, our Regency Intrastate Pipeline system had a capacity of 800 MMcf/d with 27,400 horsepower of compression and a 35 MMcf/d refrigeration plant for hydrocarbon dewpoint control.

Portions of the Regency Intrastate Pipeline system have historically operated at full capacity and represented a significant constraint on the flow of natural gas from producing fields in north Louisiana to intrastate and interstate markets in northeast Louisiana. To alleviate the constraint, we constructed a major expansion and extension of this system, which we refer to as the Regency Intrastate Enhancement Project. The project quadrupled the system s capacity from the capacity that existed prior to the commencement of the project. The completion of the Regency Intrastate Enhancement Project enables us to provide transportation services from the three largest natural gas producing fields in Louisiana.

The Regency Intrastate Enhancement Project was a multi-phase project designed to relieve bottlenecks on certain sections of the pipeline and to access new sources of supply and markets. We began planning this project in January 2005 and started construction in May 2005. We completed the project in December 2005.

The total cost of this project is approximately $157.0 million, and included the 40 mile expansion of our existing Regency Intrastate Pipeline system and the addition of an 80-mile, 30-inch diameter pipeline extension to the Regency Intrastate Pipeline system supported by approximately 9,500 horsepower of additional compression. The project has extended our transportation services into additional major producing fields in north Louisiana, connected our system to other pipelines in northeast Louisiana, and has increased the capacity of the pipeline to 800 MMcf/d.

During the year ended December 31, 2005 (most of which preceded completion of the Regency Intrastate Enhancement Project), our Regency Intrastate Pipeline system had average throughput of 258,000 MMBtu/d.

One of our motivations in constructing the Enhancement Project was to enable our customers to reach markets offering more favorable prices by interconnecting with other pipelines in northeast Louisiana. As of December 31, 2005, the Regency Intrastate Pipeline system could deliver gas to two 250 MMcf/d pipeline interconnects. Since then, three additional interconnects have been completed: two 250 MMcf/d pipeline interconnects and a 500 MMcf/d pipeline interconnect.

Through March 28, 2006, we have signed definitive agreements for 466,000 MMBtu/d of firm transportation and 404,000 MMBtu/d of interruptible transportation on the Regency Intrastate Pipeline system. We are engaged in discussions with other parties interested in utilizing the remaining firm system transportation capacity.

Business Strategies

Our management team is dedicated to increasing the amount of cash available for distribution to each outstanding unit. We intend to achieve this by pursuing organic growth projects that yield attractive returns and by capitalizing on accretive acquisition opportunities.

Our specific strategies include:

Implementing cost-effective organic growth opportunities. We intend to build natural gas gathering assets, processing facilities and transportation lines that enhance our existing systems and our ability to aggregate supply and to access premium markets for that supply. We will emphasize projects that increase volume throughput and are expected to generate attractive returns, such as our Regency Intrastate Enhancement Project and our project to provide gathering facilities for a long-term exploration and development program under an existing letter of intent with a producer in the Mid-Continent area. We are also evaluating, but have not yet made any decision to pursue, other organic growth projects. The projects under consideration include:

- Expansion of our Regency Intrastate Pipeline west of Haughton to relieve capacity constraints;
- extensions of the pipeline east into other fields beyond Winnsboro;
- construction and installation of a refrigeration plant at Longwood or Sibley or both;
- construction of additional compression at our Mainline Compressor Station;
- construction of a storage facility in proximity to the Regency Intrastate Pipeline in conjunction with a third party; and
- initiation and construction of step out expansion projects for our Waha gathering system.

Continuing to enhance profitability of our existing assets. We intend to increase the profitability of our existing asset base by identifying new business opportunities, adding new volumes of natural gas supplies, undertaking additional initiatives to enhance utilization and continuing to reduce costs. As an example, until recently, the NGLs produced by our processing plants were sold to third parties as mixed NGLs. In September 2005, we began delivering the mixed NGLs produced by our

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processing plants to operators of fractionation facilities for fractionation for our account. We then sell the individual components, such as ethane, propane and isobutane, directly to marketing companies, refineries and other wholesalers. We believe this marketing function will allow us to earn additional margins from the sale of the NGLs that otherwise would have been earned by the fractionator.

Pursuing accretive acquisitions of complementary assets. We intend to pursue strategic acquisitions of midstream assets in or near our current areas of operation that offer the opportunity for operational efficiencies and the potential for increased utilization and expansion of those assets. We also intend to pursue opportunities in new regions with significant natural gas reserves and high levels of drilling activity. We believe that there will be additional acquisition opportunities as a result of the ongoing divestiture of midstream assets by large industry participants.

Continuing to reduce our exposure to commodity price risk. Because of the volatility of natural gas and NGL prices, we attempt to operate our business in a manner that allows us to mitigate the impact of fluctuations in commodity prices and to generate stable cash flows. 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. We have reduced and intend to continue to reduce, when the opportunity arises, our commodity price exposure by replacing keep-whole contracts with fee based or percentage-of-proceeds gas processing contracts. We have executed swap contracts settled against ethane, propane, butane and natural gasoline market prices, supplemented with crude oil put options. (Historically, changes in the prices of heavy NGLs, such as natural gasoline, have generally correlated with changes in the price of crude oil.) As a result, we have hedged approximately 95% of our expected exposure to NGL prices in 2006, approximately 75% in 2007 and approximately 50% in 2008. We continually monitor our hedging and contract portfolio and expect to continue to adjust our hedge position as conditions warrant.

Improving our credit ratings. We are committed to improving our credit ratings. The current credit ratings on our debt under our credit facilities are B+ by Standard & Poor s and B1 by Moody s. The additional revenue and cash flow resulting from the completed Regency Intrastate Enhancement Project will significantly improve our credit statistics that are considered by the rating agencies.

We intend to finance our growth projects through a combination of funds available under our credit facility, commercial bank borrowings and the issuance of debt and equity securities. Given our policy of distributing available cash, we may not be able to finance such growth through the application of internal cash flow.

Competitive Strengths

We believe that we are well positioned to execute our strategies and to compete in the natural gas gathering, processing, marketing and transportation businesses based on the following competitive strengths:

We have a significant market presence in major natural gas supply areas. We have a significant market presence in each of our operating areas, which are located in some of the largest and most prolific gas-producing regions of the United States: the Louisiana-Mississippi-Alabama Salt basin in north Louisiana, the Delaware and Devonian basins of west Texas and the Hugoton and Anadarko basins in the mid-continent area. Our geographical diversity reduces our reliance on any particular region, basin or gathering system. Each of these producing regions is well-established with generally long-lived, predictable reserves, and our assets are strategically located in each of the regions. Currently, these areas are experiencing increased levels of natural gas exploration, development and production activities as a result of strong demand for natural gas, attractive recent discoveries, infill drilling opportunities and the implementation of new exploration and production techniques.

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Our recently completed Regency Intrastate Enhancement Project will provide us with the opportunity to increase significantly our fee-based transportation throughput and cash flow. Prior to the completion of the Regency Intrastate Enhancement Project, a portion of the Regency Intrastate Pipeline system was at full capacity and was not able to capitalize on the current significant constraint on the flow of natural gas from prolific producing fields in north Louisiana to intrastate and interstate markets in northeast Louisiana. As a result of this bottleneck in the pipeline, we had not been able to increase significantly the throughput on the pipeline despite an increase in drilling and production in the area. Our Regency Intrastate Enhancement Project has substantially increased the pipeline s capacity by alleviating the bottleneck and extending the pipeline to additional markets in northeast Louisiana. We expect this expansion project will provide us with significant additional transportation throughput volumes and stable, fee-based cash flow.

We have the financial flexibility to pursue growth opportunities. The borrowing limit under our revolving credit facility is $160 million. At December 31, 2005 we had borrowed $50 million against this facility. This revolving credit facility provides us with the liquidity and financing flexibility we will need to execute our business strategy. We remain committed to maintaining a balanced capital structure which will afford us the financial flexibility to fund expansion projects and other attractive investment opportunities.

We have an experienced, knowledgeable management team with a proven track record of performance. Our management team has a proven track record of enhancing value through the investment in and the acquisition, exploitation and integration of energy assets. Our senior management has an average of over 20 years of industry related experience. Our team s extensive experience and contacts within the midstream industry provide a strong foundation and focus for managing and enhancing our operations for accessing strategic acquisition opportunities and for constructing new assets. Members of our senior management team have a substantial economic interest in us.

We are affiliated with HM Capital a leading private equity investment firm headquartered in Dallas, Texas. Our affiliation with HM Capital provides us with significant benefits. We expect that our relationship with HM Capital will provide us with several significant benefits, including access to a significant pool of operational, transactional and financial professionals, multiple sources of capital and increased exposure to acquisition opportunities. HM Capital is a leading sector focused private equity firm and is currently managing and investing a $1.6 billion fund. Since the firm s founding in 1989, HM Capital has completed more than 150 transactions in its core sectors for a total transaction value in excess of $26 billion.

Industry Overview

General. Raw natural gas produced from the wellhead is gathered and delivered to a processing plant located near the production, where it is treated and dehydrated and then processed through cryogenic or other processing facilities. Natural gas processing involves the separation of raw natural gas into pipeline quality natural gas, principally methane, and mixed NGLs. It also 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 end users. Mixed NGLs that are produced by processing raw natural gas are typically transported via NGL pipelines or by truck to a fractionator, which separates the NGL into its components, such as ethane, propane, normal butane, isobutane and natural gasoline. NGLs are then sold to end users.

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

Overview of U.S. market. The midstream natural gas industry is the link between exploration and production of raw natural gas and the delivery of its components to end-use markets. The midstream natural gas industry in North America includes approximately 574 processing plants that process approximately 47 Bcf of natural gas per day and produce approximately 77 million gallons per day of NGLs. 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 continues to be a critical component of energy consumption in the United States. According to the Energy Information Administration, or EIA, total annual domestic consumption of natural gas is expected to increase from approximately 22.2 trillion cubic feet, or Tcf, in 2005 to approximately 25.9 Tcf in 2015, representing an average annual growth rate of approximately 1.7%. During the five years ended December 31, 2005, the United States has on average consumed approximately 22.4 Tcf per year, while total marketed domestic production averaged approximately 19.8 Tcf per year during the same period. The industrial and electricity generation sectors currently account for the largest usage of natural gas in the United States.

Gathering and treating. The process of raw natural gas gathering begins with the drilling of wells into gas bearing rock formations. Once a well has been completed, the well is connected to a gathering system. A gathering system typically consists of a network of small diameter pipelines and, if necessary, a compression system which together collect natural gas from points near producing wells and transport it to larger pipelines for further transportation. We own and operate five large gathering systems.

Raw natural gas has a varied composition depending on the field, the formation and the reservoir from which it is produced. Raw natural gas produced in some areas may contain hydrogen sulfide, carbon dioxide, nitrogen and other impurities. Treating plants, such as the one that we own and operate at our Waha facility, remove these impurities before the natural gas is introduced to the processing plant. Our Waha facility utilizes an amine treating process, which involves a continuous circulation of a liquid chemical called amine that physically contacts the raw natural gas. The amine reacts with carbon dioxide and hydrogen sulfide, removing them from the gas stream prior to further processing.

Compression. Gathering systems are operated at design pressures that will maximize the total throughput from all connected wells. Since wells produce at progressively lower field pressures as they age, the raw natural gas must be compressed to deliver the remaining production in the ground against a higher pressure that exists in the connected gathering system. 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.

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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 downstream pipeline.

Processing. Raw natural gas produced at the wellhead is often unsuitable for long-haul pipeline transportation or commercial use and must be processed to remove the heavier hydrocarbon components and contaminants. The principal components of raw natural gas are methane and ethane, but most raw natural gas also contains varying amounts of NGLs (such as ethane, propane, normal butane, isobutane, and natural gasoline) and impurities, such as water, sulfur compounds, carbon dioxide, or nitrogen. Natural gas in commercial distribution systems is composed almost entirely of methane and ethane, with moisture and other impurities reduced to very low concentrations. Raw natural gas is processed not only to remove unwanted impurities that would interfere with pipeline transportation or use of raw natural gas, but also to separate from the gas those hydrocarbon liquids that have higher financial value as NGLs. We own and operate four cryogenic natural gas processing plants. The cryogenic process utilizes heat exchangers and a turbo-expander to cool the gas and condense the NGLs. The NGLs are then separated from the gaseous components.

Fractionation. NGL fractionation facilities separate mixed NGL streams into discrete NGL products: ethane, propane, normal butane, isobutane and natural gasoline. We do not own or operate any NGL fractionation facilities. We ship the NGLs that we produce to a fractionator. 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.

Marketing. Natural gas and NGL marketing involves the sale of the pipeline-quality gas and NGLs that are either produced by processing plants or purchased from gathering systems or other pipelines. In the fall of 2005, we began marketing NGLs 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. We own and operate the Regency Intrastate Pipeline system, an intrastate natural gas pipeline system located in north Louisiana. Our intrastate natural gas pipeline system includes a refrigeration processing plant that is utilized to reduce the hydrocarbon dewpoint of natural gas in order to meet downstream market pipeline-quality specifications.

Gathering and Processing Operations

General

We contract with producers to gather raw natural gas from individual wells or central delivery points located near our processing plants or gathering systems. In general, once we have executed a contract, we connect wells and central delivery points to our gathering lines through which the raw natural gas is delivered 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, process the gas and extract the NGLs.

We continuously seek new sources of raw natural gas supply to increase throughput volume on our systems and through our plants. We connected 44 new wells in 2004 and 117 new wells during 2005, including connections of central delivery points which may have multiple wells behind them.

All raw natural gas flowing through our gathering and processing facilities is supplied under gathering and processing contracts having fixed terms ranging from month-to-month to 20 years. Alternatively, we

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have some contracts that span the life of the oil and gas lease. For a description of our contracts, please read Our Contracts and 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 through interstate or intrastate gas transportation pipelines.

Until recently, the NGLs produced by our processing plants were sold to third parties as mixed NGLs. In September 2005, we began delivering the mixed NGLs produced by our processing plants to operators of fractionation facilities for fractionation for our account. We then sell the individual components, such as ethane, propane and butane, directly to marketing companies, refineries and other wholesalers. We believe this marketing function will allow us to earn additional margins from the sale of the NGLs that otherwise would have been earned by the fractionator.

Our natural gas gathering and processing assets consist primarily of five large natural gas gathering systems and four active cryogenic gas processing plants which are located in north Louisiana, West Texas and the mid-continent region of the United States. The following table contains certain information regarding these gathering systems and processing plants as of and for the year ended December 31, 2005:

Asset	**Length (Miles)**	**Wells Connected**	**Compression (Horsepower)**	**Throughput Capacity (MMcf/d)**
North Louisiana				
Dubach/Calhoun/Lisbon Gathering System	600	700	14,500	300
Dubach Processing Plant			7,000	50
Lisbon Processing Plant			3,000	40
West Texas				
Waha Gathering System	750	450	22,000	200
Waha Processing Plant			20,000	125
Mid-Continent				
Hugoton Gathering System	850	900	28,000	120
Mocane-Laverne Gathering System	500	350	4,000	100
Greenwood Gathering System	250	250	9,500	45
Mocane Processing Plant			3,650	50

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North Louisiana System

Our north Louisiana system includes the Dubach and Lisbon processing plants and the Dubach/ Calhoun/ Lisbon gathering system, which is a large integrated natural gas gathering and processing system located primarily in four parishes of north Louisiana and includes over 600 miles of gathering pipelines.

The following is a map of our north Louisiana gathering and processing system.

This system is located in active drilling areas in north Louisiana. Through our Dubach/ Calhoun/ Lisbon gathering system and its interconnections with our Regency Intrastate 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.

Natural Gas Supply. The natural gas supply for our north Louisiana gathering systems is derived primarily from natural gas wells located in the following four parishes in north Louisiana: Claiborne, Union, Lincoln and Ouachita. Our operating areas have experienced significant levels of drilling activity providing us with opportunities to access newly developed natural gas supplies. Natural gas production in this area has increased as a result of the additional drilling, which includes deeper reservoirs in the Cotton Valley and Hosston trends.

During the year ended December 31, 2005, we connected 62 wells to our north Louisiana gathering system.

Devon Energy Corporation and XTO Energy Inc. represented approximately 21% and 13%, respectively, of our natural gas supply in this region for the year ended December 31, 2005.

Dubach/ Lisbon/ Calhoun Gathering System. The Dubach/ Lisbon/ Calhoun gathering system consists of over 600 miles of natural gas gathering pipelines ranging in size from two inches in diameter to ten inches in diameter. The system gathers raw natural gas from producers and delivers approximately 85% of the raw natural gas to either the Dubach or Lisbon processing plants for processing. The remainder of the raw natural gas is lean natural gas, which does not require processing and is delivered directly to interstate pipelines and our Regency Intrastate Pipeline system.

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Dubach Processing Plant. The Dubach processing plant is a cryogenic natural gas processing plant that processes raw natural gas gathered on the Dubach and Calhoun gathering systems and natural gas transported on the Regency Intrastate Pipeline system. This plant, which was acquired by us in 2003, was originally constructed in 1980 and was subsequently reassembled in its present location in 1994.

Lisbon Processing Plant. The Lisbon processing plant is a cryogenic natural gas processing plant that processes raw natural gas gathered on the Lisbon gathering system. This plant, which was acquired by us in 2003, was constructed in 1980 and was subsequently reassembled in its present location in 1996.

Markets. There are numerous market outlets for the raw natural gas that we gather and the NGLs that we produce on our north Louisiana systems. The Dubach/ Lisbon/ Calhoun gathering system is directly connected to several interstate natural gas pipelines, including Texas Gas Transmission, Mississippi River Transmission and Texas Eastern Transmission, and to our Regency Intrastate Pipeline system. Our access to numerous markets, including interstate pipelines in northeast Louisiana and to several power plants located on our system, provides us with the flexibility to sell our natural gas supply into markets with the most attractive pricing.

The NGLs extracted from the raw natural gas at our processing plants are transported by a 37-mile Regency NGL pipeline to a third-party pipeline that delivers the NGLs to Mont Belvieu, Texas for fractionation by third parties.

Our primary purchasers of pipeline-quality gas on the north Louisiana gathering system are Atmos Energy Marketing, LLC, Duke Energy Field Services and Sequent, which represented approximately 64%, 11% and 10%, respectively, of the revenues from such sales for the year ended December 31, 2005. All of the NGL sales from the north Louisiana processing plants were made to Koch Hydrocarbon, LP, which provided fractionation services during this period.

West Texas System

The following is a map of our Waha gathering and processing system.

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The system covers four Texas counties surrounding the Waha Hub, one of Texas major natural gas market areas. Through our Waha gathering system, we offer producers wellhead to market services. 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 Supply. The natural gas supply for the Waha gathering system is derived primarily from natural gas wells located in four counties in west Texas near and around the Waha Hub. 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 and steady flow rates.

This area is experiencing increasing levels of oil and natural gas drilling activity as a result of strong demand for natural gas and recent discoveries. In addition, several independent exploration and production companies are pursuing more aggressive drilling programs than the major oil companies that currently are the primary producers in the area. Several of these independent exploration and production companies are developing unexploited reserves within our area of operations through new well completions and infill drilling, along with workovers and re-completions of existing wells. Additionally, there have been recent large oil and natural gas discoveries in this region by Chesapeake Energy Corporation and Anadarko Petroleum Company. We believe that our significant presence and modern and efficient asset base provides us with competitive advantages in capturing new supplies of natural gas in the region. Many of these areas of increased drilling require little to no pipeline or meter expense as producers are connecting to existing facilities.

During the year ended December 31, 2005, we connected to 24 wells to our Waha gathering system.

Duke Energy Field Services and ExxonMobil Corporation represented approximately 25% and 14%, respectively, of our natural gas supply in this region for the year ended December 31, 2005.

Waha Gathering System. The Waha gathering system consists of approximately 750 miles of natural gas gathering pipelines ranging in size from three inches in diameter to 24 inches in diameter. 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 not required to pay for a level of compression that is higher than the level it requires.

Waha Processing Plant. 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 raw natural gas processing plant. The Waha processing plant also includes an amine treating facility. The treating facility uses an amine treating process to remove carbon dioxide and hydrogen sulfide from raw natural gas that is gathered in our Waha gathering system before the natural gas is introduced to the processing plant.

Markets. The Waha gathering system has a variety of market outlets for the natural gas that we gather. The pipeline-quality gas from our gathering and processing operations can be delivered into the Waha Hub, which includes connections to several major interstate and intrastate pipelines serving California, the mid-continent and Texas natural gas markets, including Oasis Pipeline, Enterprise Texas Pipeline, Atmos Pipeline, ONEOK Westex and El Paso Natural Gas Pipeline. The NGLs extracted from the raw natural gas at the Waha processing plant are transported to ExxonMobil s NGL pipeline, which delivers the NGLs to facilities in Mont Belvieu, Texas for fractionation by third parties.

Our primary purchasers of pipeline-quality gas on the west Texas gathering system are Energy Transfer Partners, Tenaska Marketing Ventures, and BP Energy Company, which represented approximately 40%, 25% and 15%, respectively, of the revenues from such sales for the year ended December 31,

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2005. All of the NGL sales from the Waha processing plant were made to ExxonMobil Corporation, which fractionated the NGLs from these plants during this period.

Mid-Continent Systems

Our mid-continent systems include the following natural gas gathering systems primarily in Kansas and Oklahoma:

- the Hugoton gathering system, which is a large integrated natural gas gathering and processing system located in southwestern Kansas and includes approximately 850 miles of gathering pipeline;

- the Mocane-Laverne gathering system, which is a large integrated natural gas gathering and processing system located primarily in the Oklahoma Panhandle and includes approximately 500 miles of gathering pipelines and the Mocane cryogenic processing plant; and

- the Greenwood gathering system, which is a large natural gas gathering system located primarily in southwestern Kansas and includes approximately 250 miles of gathering pipelines.

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 throughput from the connected wells. Wellhead pressures are therefore adequate to access the gathering lines without the cost of wellhead compression. In addition, we process natural gas from the Mocane-Laverne gathering system at our Mocane processing plant.

The following is a map of our mid-continent gathering and processing systems.

Natural Gas Supply. 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 and the Texas panhandle. These mature basins have continued to provide generally long-lived, predictable reserves. Recent increases in production in these areas have been driven primarily by continued infill drilling, compression enhancements, and advanced well bore completion technology. In addition, the application of 3-D seismic technology in these areas has yielded better-defined reservoirs for continuing development of these basins.

During the year ended December 31, 2005, we connected 31 wells to our mid-continent gathering systems.

Occidental Petroleum Corporation and Penn Virginia Corporation provided approximately 21% and 10%, respectively, of our natural gas supply in this region for the year ended December 31, 2005.

Hugoton Gathering System. The Hugoton gathering system is located in southwestern Kansas. It consists of approximately 850 miles of natural gas gathering pipelines ranging in size from two inches in diameter to 20 inches in diameter. Substantially all of the raw natural gas gathered by the Hugoton gathering system is delivered to a third party s processing plant. We pay the third party a fee to process the gas for our account.

Mocane-Laverne Gathering System. The Mocane-Laverne gathering system is located in Beaver and Harper counties in the Oklahoma panhandle and Meade County in southwestern Kansas. It consists of approximately 500 miles of natural gas gathering pipelines ranging in size from two inches in diameter to 24 inches in diameter. The system gathers raw natural gas from producers and delivers it for processing to the Mocane processing plant.

Mocane Processing Plant. The Mocane processing plant is a cryogenic natural gas processing plant that processes raw natural gas gathered on the Mocane-Laverne gathering system. This plant was constructed in 1975 and acquired by us in 2003.

Greenwood Gathering System. The Greenwood gathering system is located in Morton and Stanton Counties in southwestern Kansas and Baca County in southeastern Colorado. It consists of approximately 250 miles of natural gas gathering pipelines ranging in size from four inches in diameter to 20 inches in diameter. The raw natural gas gathered by this system is delivered to a third party s processing plant. We pay the third party a fee to process the gas for our account.

Markets. The pipeline-quality gas from our gathering and processing operations in the mid-continent area is delivered primarily into Panhandle Eastern Pipeline to serve markets in the mid-continent and upper Midwest. This gas can also be sold into the ANR Pipeline via the North Kiowa system or via the CIG Pipeline or can be pooled through BP s Jayhawk processing plant and Pioneer Natural Resources Santanta processing plant.

The NGLs extracted from the raw natural gas at our gathering and processing plants are transported by a third party NGL pipeline that delivers the NGLs to the Conway Hub in Kansas for fractionation by a third party.

Our primary purchasers of pipeline-quality gas on the mid-continent gathering systems are Seminole Energy Services, LLC, BP Energy Company, and Cinergy Marketing and Trading, LP, which represented 37%, 29% and 21%, respectively, of the revenues from such sales for the year ended December 31, 2005. All of the NGL sales from the mid-continent processing plants were made to Koch Hydrocarbon, LP, which fractionated these NGLs during this period.

Other Processing Systems

We also own the Lakin processing plant, which is a cryogenic processing plant with nitrogen rejection and helium recovery capabilities. This plant has a capacity of 80,000 Mcf/d. The plant was constructed in 1995 and was acquired by us in 2003. Through July 31, 2005, the Lakin processing plant processed raw natural gas received from the Hugoton gathering system. As part of our previously planned strategy, we suspended operations at the Lakin processing plant (subject to intermittent resumption) as of August 1, 2005. Suspending the operations of the plant allowed us to renegotiate certain unfavorable keep-whole processing contracts covering gas processed at the plant and replace them with fee-based contracts and to avoid charges for transporting natural gas from the Hugoton gathering system through a third party pipeline out of the tailgate of the Lakin plant. All of the gas from the Hugoton gathering system is now

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processed at a third party processing plant for our account for a fee. We are currently evaluating opportunities to utilize the Lakin processing plant, which may include connecting a new source of supply to the plant or moving the plant to another area.

Transportation Operations

General. We own and operate a 320-mile intrastate natural gas pipeline system, known as the Regency Intrastate Pipeline system, in north Louisiana extending from northwest Louisiana to northeast Louisiana. This system includes 27,400 horsepower of compression and a 35 MMcf/d refrigeration plant for hydrocarbon dewpoint control. The following map presents the location of the Regency Intrastate Pipeline system, including the Regency Intrastate Enhancement Project described below:

The following table contains certain information regarding the Regency Intrastate Pipeline system prior to the commencement of construction and following the completion of the Regency Intrastate Enhancement Project:

Asset	Length (Miles)	Compression (Horsepower)	Throughput Capacity (MMcf/d)	Market Outlets
Regency Intrastate Pipeline System				
Pre-Enhancement Project	200	17,900	200	6
Post-Enhancement Project	320	27,400	800	11
Haughton Refrigeration Processing Plant			35	

During the years ended December 31, 2005 and 2004, the Regency Intrastate Pipeline system had average throughput of 258,194 MMBtu/d and 189,640 MMBtu/d, respectively. Natural gas generally flows from west to east on the pipeline from wellhead connections or connections with other gathering systems.

Prior to the completion of our Regency Intrastate Enhancement Project, our Regency Intrastate Pipeline system consisted of the following components:

the Elm Grove System, a 31-mile, 12-inch diameter pipeline placed in operation in 1974 that extends from Southwestern Electric Power Company s Arsenal Hill Power Plant in Caddo Parrish eastward to the Elm Grove natural gas field in Bossier Parish;

the North Louisiana Pipeline, a 23-mile, 12-inch diameter pipeline and a 25-mile, 16-inch diameter pipeline placed in service in 1989 that extends from the tie-in point with the Elm Grove System to an interconnection with a pipeline owned by Southern Natural Gas Company in Bienville Parish;

the Metco Pipeline, a 19-mile, 20-inch diameter pipeline placed in operation in 1990 that extends from the interconnect point with the pipeline owned by Gulf States Transmission Corporation to the western end of the Elm Grove System interconnect;

the Ruston System, a 12-mile, six-inch diameter pipeline, a six-mile, 12-inch diameter pipeline and a 0.5-mile, four-inch diameter pipeline located in Jackson and Lincoln Parishes in northeast Louisiana and interconnects with pipelines owned by Southern Natural Gas Co. and Duke Energy Field Services;

the Panda Pipeline, a 20-mile, 20-inch diameter pipeline and an 11-mile, 24-inch diameter pipeline placed in operation in 2002 that extends from the eastern portion of the North Louisiana Pipeline to an interstate pipeline that transports natural gas exclusively to a power generation plant; and

the Dubach Extension, an eight-mile, 12-inch diameter pipeline that was constructed as part of our Enhancement Project and is described in further detail below.

Our Regency Intrastate Pipeline system includes a natural gas refrigeration conditioning plant. At the plant, we condition natural gas to remove NGLs to ensure that it meets pipeline-quality specifications so that it can be transported on our intrastate pipeline. The NGLs extracted from the raw natural gas at our refrigeration conditioning plant are sold to a third party at the tailgate of the plant.

Our primary purchasers of pipeline-quality gas on the Regency Intrastate Pipeline system are Alabama Gas Corporation, Southwestern Power and Electric Company and Louis Dreyfus Energy, which represented approximately 66%, 9% and 9%, respectively, of the external revenues from such sales for the year ended December 31, 2005.

Enhancement Project. Portions of the Regency Intrastate Pipeline system have historically operated at full capacity and represented a significant constraint on the flow of natural gas from producing fields in north Louisiana to intrastate and interstate markets in northeast Louisiana. As a result, in 2005, we undertook to construct and completed a major expansion and extension of this system, which we refer to as the Regency Intrastate Enhancement Project. The project quadrupled the system s capacity from the capacity that existed prior to the commencement of the project.

The Regency Intrastate Enhancement Project was a multi-phase project designed to relieve bottlenecks on certain sections of the pipeline and to extend the pipeline in order to access new sources of supply and markets. We began planning this project in January 2005 and started construction in May 2005. We completed the project in December 2005.

The total cost of this project is approximately $157.0 million. On July 1, 2005, we completed the Dubach extension, which consists of an eight mile, 12-inch diameter pipeline and connection to the Panda Pipeline to our Dubach processing plant located on our north Louisiana gathering system. The Dubach extension provides the Regency Intrastate Pipeline system with direct access to four interstate pipelines that are directly connected to the Dubach processing plant.

As of October 1, 2005, we had completed construction of the second phase of this project, a 40-mile, 24-inch diameter system loop along a portion of our existing pipeline. This additional pipeline increased the capacity of the Regency Intrastate Pipeline system by 100 MMcf/d.

In December 2005, we completed construction of the final phase of this project, which includes an 80-mile, 30-inch diameter pipeline extension to the Regency Intrastate Pipeline system providing transportation services from several major producing fields in north Louisiana to markets in northeast Louisiana. This Winnsboro extension extends from the eastern terminus of the North Louisiana Pipeline to a point near Winnsboro, Louisiana.

In order to facilitate the enhancement of the system, we also added approximately 9,500 horsepower of compression.

As a result of the completion of the Regency Intrastate Enhancement Project, we are able to transport natural gas produced from the Vernon field, the Elm Grove field and the Sligo field, which are the three largest natural gas producing fields in Louisiana.

New Transportation Contracts. Through March 28, 2006, we have signed definitive agreements for 466,000 MMBtu/d of firm transportation and 404,000 MMBtu/d of interruptible transportation on the Regency Intrastate Pipeline system. We are engaged in discussions with other parties interested in utilizing the remaining firm system transportation capacity.

Funding of Project Costs. In July 2005, we amended our credit facilities to provide for $170 million in additional borrowing capacity, consisting of $60 million in additional term loans and $110 million in additional revolving loans. We used these amounts, together with an additional $15 million equity contribution from funds managed by HM Capital Partners and other investors, including directors and members of management (collectively, the HM Capital Investors) to complete the Regency Intrastate Enhancement Project. For information regarding the terms of the amended and restated credit facilities, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Requirements.

Interstate Pipeline Specifications. The markets to which the shippers on our Regency Intrastate Pipeline ship natural gas include interstate pipelines. These interstate pipelines establish specifications for the natural gas that they are willing to accept, which include such matters as hydrocarbon dewpoint, temperature and impurities including water, sulphur, carbon dioxide and hydrogen sulphide. 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, that pipeline may refuse to accept all or a part of the natural gas scheduled for delivery to it.

In certain cases, the mix of natural gas that we transport for shippers on our Regency Intrastate Pipeline does not meet the dewpoint specification of one of our interconnected interstate pipelines. In October 2005, we began construction of a refrigeration plant at Elm Grove to remove hydrocarbons and allow the natural gas to meet these dewpoint specifications. We expect the plant to be completed by the end of April 2006.

An interstate pipeline curtailed shipments through its existing interconnect with our pipeline in late November 2005. We and our shippers have thus far been able to find alternative markets for all the curtailed gas. If for some reason we are unable to do so during the period prior to completion of the Elm Grove refrigeration plant, we may be required to shut-in non-conforming gas delivered to us for transportation. We estimate that a reduction of approximately 25,000 MMBtu/d would substantially restore the total mix of transported gas to these dewpoint specifications.

Also, lean or processed gas that we transport or are scheduled to transport may be mixed with gas that does not meet dewpoint specifications, which lowers the overall dewpoint of the natural gas stream and allows us to avoid having to shut-in any gas. As a result of the introduction of a significant quantity of lean gas into the system following the completion of the Regency Intrastate Enhancement Project, the interstate pipeline has suspended its curtailments.

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Other Assets

Gulf States Transmission, our small interstate pipeline, consists of approximately 10 miles of 20-inch pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana. The pipeline has a Federal Energy Regulatory Commission (FERC) certificated capacity of 150 MMcf/d.

Our Contracts

Gathering and Processing Contracts. We contract with producers to gather raw natural gas from individual wells or central delivery points located near our gathering systems and processing plants. Once we have executed a contract with the producer, we connect the producer s wells and central delivery points to our gathering lines through which the natural gas is delivered to a processing plant (whether owned and operated by us or a third party) for a fee. We obtain supplies of raw natural gas for our gathering and processing facilities under contracts having terms ranging from month-to-month to twenty years or 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. Additionally, it is common for a percentage-of-proceeds or keep-whole contract to have a fee component in addition to its commodity-sensitive component. For a description of our fee-based arrangements, percent-of-proceeds arrangements, and keep-whole arrangements, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Our Operations.

At December 31, 2005, the mixture of our gathering and processing contracts by category and by geographic region is set forth in the following table:

	Nature of Contract (Measured by 2005 volumes)		
	Keep-Whole	**POP**	**Fee-Based**
Geographic Region			
North Louisiana(1)	29.3%	57.9%	12.8%
West Texas	18.0%	44.5%	37.5%
Mid-Continent	31.3%	46.8%	21.9%
Total Gathering and Processing	26.1%	48.5%	25.4%

Note (1) approximately 24% of 29% reported keep-whole exposure in north Louisiana is attributable to a package of bypassable gas controlled by us. We only process this gas when economically beneficial.

Fee Transportation Contracts. We provide natural gas transportation services on the Regency Intrastate Pipeline 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. Our obligation to provide firm transportation service means that we are 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. Our obligation to provide interruptible transportation service means that we are only obligated to transport natural gas nominated by the shipper 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 our transportation services under the terms of our contracts and under an operating statement that we have filed and maintain with FERC with respect to transportation authorized under section 311 of the Natural Gas Policy Act.

Merchant Transportation Contracts. We perform a limited merchant function on our Regency Intrastate Pipeline system. 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 at which we sell the natural gas at market price. We regard the total segment margin with respect to those purchases and sales as the economic equivalent of a fee for our transportation service.

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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.

Competition

The natural gas gathering, processing, marketing and transportation businesses are highly competitive. 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 in each region include:

North Louisiana: CenterPoint Energy Gas Marketing Company; Gulf South Pipeline L.P.; PanEnergy Louisiana Intrastate, LLC (Pelico).

West Texas: Sid Richardson Energy Services Co.

Mid-Continent: Duke Energy Field Service, L.P.; ONEOK Energy Marketing and Trading, L.P.; Penn Virginia Corporation.

In transporting natural gas across north Louisiana, we face major competition from CenterPoint Energy Gas Marketing Company, Gulf South Pipeline, L.P., and Texas Gas Transmission, LLC. Many of our competitors have substantially greater resources, both in capital and in access to shippers supplies of natural gas than we do. Competition in natural gas transportation is characterized by price of transportation, the nature of the markets accessible from a transportation pipeline and nature of service.

Risk Management

To manage commodity price risk, we have implemented a risk management program under which we seek to match sales prices of commodities (especially natural gas) 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 (specifically NGLs).

To the extent that we purchase or commit contractually to purchase natural gas that we gather and process, we are exposed to commodity price changes in both the natural gas and NGL 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 when recovery of ethane as an NGL is uneconomical.

As a consequence of our processing contract portfolio, we derive a portion of our earnings from a long position in NGL products, resulting from the purchase of natural gas for our account or from the payment of processing charges in kind, that are exposed to commodity price fluctuations. Shortly after the acquisition of our company by HM Capital, we implemented a policy of hedging this commodity price risk by purchasing a series of contracts relating to swaps of individual NGL products and crude oil puts. Our hedging position and needs to supplement or modify our position are closely monitored by the Risk Management Committee of our Managing General Partner. Please read Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures about Market Risk for information regarding the status of these contracts and the accounting treatment to be accorded to them. As a matter of policy we do not acquire forward contracts or derivative products for the purpose of speculating on price changes.

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Regulation

Intrastate Pipeline Regulation. To the extent that our Regency Intrastate Pipeline system transports natural gas in interstate commerce, the rates, terms and conditions of that transportation service are subject to the jurisdiction of FERC, under Section 311 of the Natural Gas Policy Act of 1978, or NGPA, which regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of an interstate natural gas pipeline. Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. NGPA Section 311 rates deemed fair and equitable by FERC are generally analogous to the cost-based rates that FERC deems just and reasonable for interstate pipelines under the Natural Gas Act, or NGA. Certain aspects of FERC rate regulation under the NGA are discussed under the section below entitled *Regulation Interstate Pipeline Regulation.* Additionally, the terms and conditions of service set forth in the intrastate pipeline s Statement of Operating Conditions are subject to FERC approval.

FERC Pipeline Regulation. Regency Intrastate Gas LLC, or RIGS, is one of our subsidiaries which transports interstate gas in Louisiana under Section 311 (a) (2) of the NGPA for many of its shippers. FERC approves Section 311 (a)(2) transportation rates for our intrastate pipeline (as for others) typically on a cost of service basis. FERC requires most of these pipelines, including RIGS, to file triennial rate petitions either justifying its existing rates or requesting new rates. RIGS most recent Section 311 maximum rates were established by a FERC order dated September 26, 2005, and were set for firm transportation at $0.15 per MMBtu/d reservation charge, with a $0.05 MMBtu commodity charge, and for interruptible transportation at $0.20 per MMBtu/d. RIGS is obligated to file its next Section 311 rate case no later than May 1, 2008.

Under Section 311, intrastate pipelines providing transportation service under NGPA Section 311 may avoid jurisdiction that would otherwise apply under the Natural Gas Act of 1938, or NGA.

Any failure on our part:

- To observe the service limitations applicable to transportation service under Section 311,
- to comply with the rates approved by FERC for Section 311 service,
- to comply with the terms and conditions of service established in our FERC-approved Statement of Operating Conditions, or
- to comply with applicable FERC regulations, the NGPA or certain state laws and regulations

could result in an alteration of our jurisdictional status or the imposition of administrative, civil and criminal penalties, or both.

Our Regency Intrastate Pipeline system in north Louisiana is subject to regulation by various agencies of the State of Louisiana. Louisiana s Pipeline Operations Section of the Department of Natural Resources Office of Conservation 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. Historically, apart from pipeline safety, it has not acted to exercise this jurisdiction respecting gathering 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.

Interstate Pipeline Regulation. FERC also has broad regulatory authority over the business and operations of interstate natural gas pipelines, such as the Gulf States Transmission Corporation pipeline. Under the Natural Gas Act, 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. Gulf States Transmission holds a FERC-approved tariff setting forth cost-based rates, terms and conditions for services to shippers wishing to take interstate transportation service. FERC s authority extends to:

- rates and charges for natural gas transportation and related services;
- certification and construction of new facilities:
- extension or abandonment of services and facilities;
- maintenance of accounts and records;
- relationships between the pipeline and its energy affiliates;
- terms and conditions of service;
- depreciation and amortization policies;
- accounting rates for ratemaking purposes;
- acquisition and disposition of facilities;
- initiation and discontinuation of services; and
- information posting requirements.

FERC regulation and policy determine whether and to what extent an interstate pipeline s costs are eligible for inclusion in that pipeline s cost-of-service for purposes of establishing the pipeline s maximum just and reasonable rates for service. Under new FERC rate policy, pipelines are permitted to include, as part of their cost-of-service, a full income tax allowance for all entities owning the public utility asset, provided that such entities or individuals are subject to an actual or potential tax liability to be paid on income derived from the public utility asset. FERC s income tax allowance policy is, however, currently being challenged, and may be subject to change in the future. As a consequence, we cannot provide any assurance that we will be able to continue to include an income tax allowance in the cost-of-service used to set Gulf States Transmission Corporation s maximum just and reasonable rates. Additionally, whether and to what extent an intrastate pipeline company providing service under NGPA Section 311 is allowed to include an analogous income tax allowance in its cost-of-service for ratemaking purposes is currently unclear and is, in any event, likewise subject to change in the future.

Gathering Pipeline Regulation. Section I (b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. We own a number of natural gas pipelines that we believe meet the traditional tests FERC has used to establish a pipeline s status as a gatherer not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress.

State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and in some instances complaint-based rate regulation. We are subject to state ratable take and common purchaser statues. 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 statues are designed to prohibit discrimination in favor of one producer over another or one source of supply over another. These statues 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 both the state and the federal levels now that FERC has taken a less stringent approach to regulation of the gas gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. For example, the Texas Railroad Commission, or TRRC, has approved changes to its regulations governing transportation and gathering services performed by intrastate pipelines and gatherers, which 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.

Sales of Natural Gas. 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 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 is continually proposing and implementing new rules and regulations affecting interstate transportation, including interstate natural gas pipelines and natural gas storage facilities. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. We do not believe that we will be affected by any such FERC action in a manner materially differently than other natural gas companies with whom we compete.

Oil Price Controls and Transportation Rates. Sales of crude oil, condensate and NGLs are not currently regulated. Prices of these products are set by the market rather than by regulation. Effective as of January 1, 1995, FERC implemented regulations establishing an indexing system for transportation rates for oil, NGLs and other products that allowed for an increase in the cost of transporting oil to the purchaser. The implementation of these regulations has not had a material adverse effect on our results of 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 relating to the release of hazardous substances or wastes into the environment. As with the industry generally, compliance with existing and anticipated environmental laws and regulations increases our overall costs 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 the environmental laws.

Any failure to comply with applicable environmental laws and regulations, including those relating to obtaining required governmental approvals, may result in the assessment of administrative, civil or criminal penalties, requirements to perform investigatory or remedial activities and the issuance of injunctions or construction bans or delays. 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 consolidated results of operations or financial condition.

Under an omnibus agreement, Regency Acquisition LP agreed to indemnify us in an aggregate amount not to exceed $8.6 million generally for three years after February 3, 2006 for certain environmental noncompliance and remediation liabilities associated with the assets transferred to us and occurring or existing before that date. For a discussion of the omnibus agreement, please read Item 13 Certain Relationships and Related Party Transactions Omnibus Agreement.

Hazardous Substances and Waste. To a large extent, the environmental laws and regulations affecting our operations relate to the release of hazardous substances or solid waste into soils, groundwater and surface water and include measures to control pollution of the environment. These laws and regulations generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous wastes and may require investigatory and corrective actions of facilities where such waste may have been released or disposed. For example, the Comprehensive Environmental Response, Compensation and Liability Act, or 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 hazardous substance into the environment. These persons include the owner or operator of the site where a release occurred and companies that disposed or arranged for the disposal of the hazardous substances that have been released into the environment. Under CERCLA, these persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the Environmental Protection Agency, or EPA, and, in some instances, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Although petroleum as well as natural gas and NGLs are excluded from CERCLA s definition of a hazardous substance, in the course of our ordinary operations we generate wastes that may fall within that definition. We may be responsible under CERCLA for all or part of the costs required to clean up sites at which such wastes have been disposed. We have not received any notification that we may be potentially responsible for cleanup costs under CERCLA or analogous state laws.

We also generate both hazardous and nonhazardous solid wastes that are subject to requirements of the federal Resource Conservation and Recovery Act, or RCRA and comparable state statutes. From time to time, the EPA has considered the adoption of stricter disposal standards for nonhazardous wastes, including crude oil and natural gas wastes. We are not currently required to comply with a substantial portion of the RCRA requirements because our operations generate minimal quantities of hazardous wastes. It is possible, however, 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. Changes in applicable regulations may result in an increase in our capital expenditures or plant operating expenses.

We currently own or lease properties 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 other solid wastes have been disposed of or released on or under various properties during the operating history of those facilities that are now owned or leased by us. Notwithstanding the possibility that these dispositions of wastes may have occurred during the ownership of these assets by others, these properties and wastes may be subject to CERCLA, RCRA and analogous 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 property contamination (including groundwater contamination) or to perform remedial operations to prevent the migration of contamination.

It is this possibility that led the management of Regency Gas Services to negotiate for the inclusion of environmental indemnity provisions in the agreement under which it agreed to acquire assets from El Paso Field Services LP and its affiliates in 2003. Those provisions included an indemnity of Regency Gas Services by the El Paso sellers against a variety of environmental claims for a period of five years up to an aggregate of $84 million. They also included an escrow of $9 million relating to claims, including environmental claims, under the El Paso agreement.

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Regency Gas Services has submitted a claim against the El Paso sellers for a variety of environmental defects at these assets, and the El Paso sellers have agreed to maintain $5.4 million in the escrow account to pay any claim amounts for environmental matters ultimately deemed to be covered by their indemnity. This amount represents the upper end of the estimated remediation cost calculated by Regency based on the results of its investigations of these assets.

A Phase I environmental study was performed on our west Texas assets by an environmental consultant engaged by us in connection with our investigation of those assets prior to our purchase of them in 2004. The study indicated that most of the identified environmental contamination had either been remediated or was being remediated by the previous owners or operators of the properties. We believe that the likelihood that we will be liable for any significant potential remediation liabilities identified in the study is remote.

At the time of the negotiation of the agreement to acquire the west Texas assets in the first quarter of 2004, management of Regency Gas Services obtained an insurance policy against specified risks of environmental claims up to $10 million. The premiums on the insurance policy were prepaid for a period of 10 years or until February 2014. This policy covers third party claims for on-site and off-site cleanup costs and personal injury/property damage arising from pre-February 2004 contamination or incidents, with a $100,000 per claim deductible.

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 expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. 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 becoming subject to increasingly stringent regulations, including regulations that require the installation of control technology or the implementation of work practice 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.

ODEQ Notice of Violation. In March 2005, the Oklahoma Department of Environmental Quality, or ODEQ, sent us a notice of violation, alleging that we are operating the Mocane processing plant in Beaver County, Oklahoma in violation of the National Emission Standard for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities, or NESHAP, and the requirements to apply for and obtain a federal operating permit (Title V permit). After seeking and obtaining advice from the Environmental Protection Agency, the ODEQ issued an order requiring us to apply for a Title V permit with respect to emissions from the Mocane processing plant by April 2006. No fine or penalty was imposed by the ODEQ. While we believe that the basis for the allegations identified in the notice of violation is inapplicable to the Mocane processing plant, we intend to comply with the order. Resolution of this matter will not have any materially adverse effect on our consolidated results of operations.

TCEQ Notice of Enforcement. In November 2004, the Texas Commission on Environmental Quality, or TCEQ, sent a Notice of Enforcement, or NOE, to us relating to the operation of the Waha processing plant in 2001 before it was acquired by us. We settled this NOE with the TCEQ in November 2005.

Absent the physical or operational changes at the Waha processing plant that allegedly occasioned the NOE, the air emissions at the plant would have been limited, based on the plant s grandfathered status under the relevant federal statutory standards, only by historical amounts until 2007. In anticipation of the expiration of that status and regardless of the outcome of the NOE, we submitted to the TCEQ in early February 2005 an application for a state air permit for emissions from the Waha plant predicated on the construction of an acid gas reinjection well and, after completion of the well and facilities, the reinjection of the emitted gases. That permit has been issued and requires completion of construction of the well and facilities by the end of February 2007. We estimate the capital expenditure relating to the well and facilities at $6.0 million.

Clean Water Act. The Federal Water Pollution Control Act of 1972, as renamed and amended as the Clean Water Act, and similar 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 National Pollutant Discharge Elimination System, or NPDES, or state permit, or both, must be obtained to discharge pollutants into state and federal waters. The Clean Water Act and analogous state laws assess administrative, civil and criminal penalties for discharges of unauthorized pollutants into the water and impose substantial liability for the costs of removing spills from such waters. In addition, the Clean Water Act and analogous state laws require that individual permits or coverage under general permits be obtained by covered 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 consolidated results of operation or financial position.

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.

Employee Health and Safety. We are subject to the requirements of the Occupational Safety and Health Act, referred to as 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, record keeping 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 U.S. Department of Transportation under the Hazardous Liquid Pipeline Safety Act, or 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 make certain reports and provide information as required by the Secretary of Transportation. We believe our liquids pipelines are in substantial compliance with applicable HLPSA requirements.

Our intrastate pipeline facilities are subject to regulation by the U.S. Department of Transportation, or the DOT, under the Natural Gas Pipeline Safety Act of 1968, as amended, or the NGPSA, pursuant to which the DOT has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. The NGPSA covers natural gas, crude oil, carbon dioxide, NGL and petroleum products pipelines and requires any entity that owns or operates pipeline facilities to comply with the regulations under the NGPSA, to permit access to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation. We believe that our pipeline operations are in substantial compliance with applicable NGPSA requirements; however, we cannot predict the effect of any new or amended laws and regulations or reinterpretation of existing laws and regulations on our future compliance with the NGPSA.

Louisiana administers federal pipeline safety standards under the NGPSA. The Louisiana Office of Conservation, Pipeline Division, monitors Louisiana intrastate pipeline operators to ensure safety and compliance with regulations. Among other things, the Louisiana Office of Conservation conducts pipeline inspections and accident investigations, and it oversees compliance and enforcement, safety programs, and record maintenance and reporting. The rural gathering exemption under the NGPSA currently exempts our gathering facilities from jurisdiction under that statute. The rural gathering exemption, however, may be restricted in the future, and that exemption does not apply to our intrastate natural gas pipeline facilities. With respect to recent pipeline accidents in other parts of the country, Congress and the DOT have passed or are considering heightened pipeline safety requirements.

Employees

Our Managing GP or its affiliates employ approximately 153 employees, of whom 103 are field operating employees and 50 are mid- and senior-level management and staff.

None of these employees is represented by a labor union and there are no outstanding collective bargaining agreements to which our Managing GP or any of its affiliates is a party. Our Managing GP believes that it has good relations with its employees.

Legal Proceedings

We are not a party to any material litigation. See, however, the discussion of the TCEQ NOE and the ODEQ NOV under Environmental Matters TCEQ Notice of Enforcement and Environmental Matters ODEQ Notice of Violation. Our operations 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.

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.

Available Information

Regency Energy Partners LP files annual and quarterly financial 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.

The Partnership makes its SEC filings available to the public, free of charge and as soon as practicable after they are filed with the SEC, through its Internet site located at http://www.regencyenergy.com. Our annual reports are filed on Form 10-K, our quarterly reports are filed on Form 10-Q, and current-event reports are filed on Form 8-K.

ITEM 1A. Risk Factors.

Limited partner interests are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. You should consider carefully the following risk factors together with all of the other information included in this report in evaluating an investment in our common units.

If any of the following risks were actually to occur, our business, financial condition, results of operations or cash flows could be materially adversely affected. In that case, we might not be able to pay the minimum quarterly distribution on our common units, the trading price of our common units could decline and you could lose all or part of your investment.

Risks Related to Our Business

We may not have sufficient cash from operations to enable us to pay the minimum 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 the minimum quarterly distribution. 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:

- 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;
- the level of our operating costs, including reimbursement of fees and expenses of our general partner; and
- prevailing economic conditions.

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, including capital expenditures incurred in connection with our enhancement projects;
- 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 on our cash flow and not solely on profitability, which is 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 make cash distributions during periods when we record net earnings for financial accounting purposes.

If we do not receive the revenues we anticipate from the Regency Intrastate Enhancement Project, our cash flow and our ability to make cash distributions to you may be adversely affected.

Our ability to pay the minimum quarterly distributions for 2006 assumes, among other things, the generation of revenues contemplated by the gas transportation contracts relating to our Regency Intrastate Enhancement Project.

Our ability to pay the minimum quarterly distributions for 2006 also assumes the generation of the revenues contemplated by the contracts that we have entered into with our customers relating to the transportation of gas on our Regency Intrastate Pipeline. If any of the following were to occur, our forecast of these revenues would be adversely affected:

- we are unable to perform the requisite transportation services for any reason,
- in the case of interruptible transportation services, our customers fail to utilize our services in whole or in part, or
- our customers fail to pay for our services for any reason, including financial distress.

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While substantial amounts of the incremental capacity resulting from the completion of the Regency Intrastate Enhancement Project has been contracted, if we are unable to utilize the remaining incremental transportation capacity, our business and our operating results could be adversely affected.

We have agreed to provide natural gas transportation services to natural gas producers in the area upon completion of the Regency Intrastate Enhancement Project, which increased our capacity on the Regency Intrastate Pipeline from 200 MMcf/d to 800 MMcf/d. We have signed definitive agreements for 466,000 MMbtu/d of firm transportation and for 404,000 MMbtu/d of interruptible transportation. We are currently transporting approximately 450,000 MMbtu/d under these existing contracts. We are engaged in discussions with various shippers interested in contracting for portions of the uncommitted capacity on the system for firm transportation of natural gas volumes. If we are unable to commit the remaining uncommitted capacity on the system to firm gas transportation contracts and the parties to existing interruptible transportation contracts fail to utilize the capacity, our business and our operating results could be adversely affected.

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 transportation pipeline systems are connected to or dependent on the level of production from natural gas wells that supply our systems and from which production will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. In order to maintain or increase throughput 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 include: the level of successful drilling activity near these 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. Currently, natural gas prices are high in relation to historical prices. For example, the twelve-month average of NYMEX daily settlement price of natural gas increased from $6.18 per MMBtu as of December 31, 2004 to $9.35 per MMBtu as of February 28, 2006. 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, the ability of producers to obtain necessary drilling and other governmental permits and regulatory changes. Because of these factors, even if additional natural gas reserves were discovered in areas served by our assets, producers may choose not to develop those reserves. If we were not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells due to reductions in drilling activity or competition, throughput 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, financial condition and ability to make cash distributions to you.

We depend on certain key producers and other customers for a significant portion of our supply of natural gas. The loss of, or reduction in volumes from, 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. Our three largest suppliers of natural gas by volume for the year ended December 31, 2005, Oxy USA Inc., Duke Energy Field Services LLC and ExxonMobil Corporation accounted for approximately 24% of our total natural gas supply. These contracts have terms that are either month-to-month or year-to-year. As these contracts expire, we will have to negotiate extensions or renewals or replace the contracts with those of other suppliers. We may be unable to obtain new or renewed contracts on favorable terms, if at all. The loss of all or even a portion of the volumes of natural gas supplied by these producers and other customers, as a result of competition or otherwise, could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to you.

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 cash flow and our ability to make cash distributions to you.

In accordance with industry practice, 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 is 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, financial condition and our ability to make cash distributions to you.

Natural gas, NGLs and other commodity prices are volatile, and a reduction in these prices could adversely affect our cash flow and our ability to make distributions to you.

We are subject to risks due to frequent and often substantial fluctuations in commodity prices. NGL 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. The NYMEX daily settlement price for natural gas for the prompt month contract in 2004 ranged from a high of $8.75 per MMBtu to a low of $4.57 per MMBtu. In 2005, the same index ranged from a high of $15.38 per MMBtu to a low of $5.79 per MMBtu. The NYMEX daily settlement price for crude oil for the prompt month contract in 2004 ranged from a high of $56.37 per barrel to a low of $32.49 per barrel. In 2005, the same index ranged from a high of $69.91 per barrel to a low of $42.16 per barrel. 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 fluctuate with changes in market and economic conditions and other factors, including:

- the impact of weather on the demand for oil and natural gas;
- 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 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 an agreed percentage of the proceeds (in cash or in-kind) from the sale at market prices of pipeline-quality gas and NGLs or NGL products resulting from our processing activities. 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 NGL prices, it is more profitable for us to process natural gas under keep-whole arrangements. When natural gas prices are high relative to NGL 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. For a detailed discussion of these arrangements, please read Item 1 Business Our Contracts.

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 deliver 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 and our hedging activities may limit potential gains.

In performing our functions in the Gathering and Processing segment, we are a seller of NGLs and are exposed to commodity price risk associated with downward movements in NGL prices. As a result of the volatility of NGL and other commodity prices in recent years, in December 2004, we initiated a plan to hedge a significant percentage of our total segment margin for the years 2005 to 2007. Under this plan, we executed swap contracts settled against ethane, propane, butane and natural gasoline market prices, supplemented with crude oil put options. (Historically, changes in the prices of heavy NGLs, such as natural gasoline, have generally correlated with changes in the price of crude oil.) As a result, we have hedged approximately 95% of our expected exposure to NGL prices in 2006, approximately 75% in 2007 and approximately 50% in 2008. 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. Our hedging transactions are intended to reduce our exposure to downward movements in NGL prices. In exchange for this reduction in exposure, however, these transactions limit our potential gains if NGL prices rise over the price established by the hedging arrangements. In addition, 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 our cash available for distribution.

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.

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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 its completion 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 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 results of operations and our ability to make cash distributions to you.

In addition, our ability to undertake to grow in this fashion will depend on our ability to finance the construction or modification project and on our ability to hire, train and retain qualified personnel to manage and operate these facilities when completed.

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

Our ability to grow depends in part on our ability to make acquisitions that result in an increase in the cash per unit generated from operations. Factors affecting our ability to do so include our abilities:

- To identify businesses engaged in managing, operating or owning gathering, compression, processing and pipeline assets for acquisitions and joint ventures;
- to obtain required financing for acquisitions and joint ventures;
- to outbid competitors for acquisition prospects;
- to analyze acquisition and joint venture prospects successfully from both an operational and financial viewpoint;
- to consummate acquisitions and joint ventures;
- to integrate acquired businesses and assets with our existing operations and to subject them to our operating and financial systems and controls; and
- to hire, train and retain qualified personnel to manage and operate our expanded business.

In addition, even though we expect an acquisition to be accretive, it may not be.

Any acquisition involves potential risks, including among others the following:

- Mistaken assumptions regarding revenues and costs, including synergies;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from sellers;
- the diversion of management s attention from other business concerns;
- unforeseen difficulties in operating in new geographic areas; and
- customer or key employee losses at the acquired business.

Our capitalization and results of operations may change significantly if we consummate any acquisitions, and you will not have the opportunity to evaluate the economic, financial or other relevant information that we will consider in determining to make those acquisitions.

Our acquisition strategy is based, in part, on our expectation of ongoing divestitures of midstream assets by large industry participants. A material decrease in such divestitures would limit our opportunities for future acquisitions and could adversely affect our operations and cash flows available for distribution to our unitholders.

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, we will depend on financing provided by commercial banks and other lenders and the issuance of debt and equity securities to finance any significant internal organic growth or acquisitions. If we are unable to obtain adequate financing from these sources, our ability to grow will be limited.

Our 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 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. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to you.

Restrictions in our credit facility limit our ability to make distributions to you and our ability to capitalize on acquisitions and other business opportunities.

Our bank credit facility prohibits us from making cash distributions during an event of default or if the payment of a distribution would cause an event of default. Our credit facility, as amended, allows us to make distributions as long as we are in compliance with the covenants in this agreement. In addition, it contains various covenants limiting our ability to incur indebtedness, to grant liens, and to engage in transactions with affiliates, as well as others requiring us to maintain certain financial ratios and tests. Our payment of principal and interest on the debt will reduce the cash available for distribution on our units, as will our obligation to repay this debt upon the occurrence of specified events involving a change of control of our general partner. Any subsequent refinancing of our current debt or any new indebtedness could have similar or greater restrictions. Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Requirements.

We have a significant amount of debt that may limit our ability to grow.

Our total outstanding long-term indebtedness under our credit facility was approximately $371.4 million at March 24, 2006. Our leverage and various limitations in our credit facility and our lack of an investment grade rating may reduce our ability to incur additional debt, engage in some transactions, and capitalize on acquisition or other business opportunities. Any subsequent refinancing of our current debt or any new indebtedness could have similar or greater restrictions. Please read Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operation Capital Requirements and Liquidity and Capital Resources.

Increases in interest rates, which have recently experienced record lows, could adversely impact our unit price and our ability to issue additional equity, make acquisitions, reduce debt or for other purposes.

The credit markets recently have experienced 50-year record lows in interest rates. If the overall economy strengthens, it is likely that monetary policy will tighten further, resulting in higher interest rates to counter possible inflation. We expect our quarterly interest payments in 2006 to range between $6.1 and $6.5 million. An increase of 100 basis points in the LIBOR rate would increase this quarterly payment by approximately $0.4 million. Additionally, interest rates on future credit facilities and debt offerings could be 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, make acquisitions, reduce debt or for other purposes.

If third-party pipelines interconnected to our processing plants become unavailable to transport NGLs, our cash flow and cash available for distribution 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. For example:

- all of the NGLs produced at our north Louisiana system are transported to Mont Belvieu on the Black Lake Pipeline, which is owned by BP Energy Company and Duke Energy Field Services;
- all of the NGLs produced at the Waha processing plant are transported to Mont Belvieu by use of Louis Dreyfus pipeline and ExxonMobil Corporation s NGL pipeline; and
- all of the NGLs produced at our mid-continent processing plants are transported to the Conway Hub in Kansas by ONEOK Hydrocarbon Southwest L.L.C. s NGL pipeline.

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 out of 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. For example, Hurricane Rita disrupted the operations of NGL pipelines and fractionators in the Houston, Texas area. As a result of these disruptions, we were forced temporarily to curtail producers in the west Texas region for approximately four days and to operate our north Louisiana processing assets in a reduced recovery mode for six days.

We are exposed to the credit risks of our key customers, and any material nonpayment or nonperformance by our key customers could reduce our ability to make distributions to our unitholders.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. For example, in January 2005, one of our customers filed for Chapter 11 reorganization under U.S. bankruptcy law although that customer has since emerged from bankruptcy court protection. Any material nonpayment or nonperformance by this customer or our key customers could reduce our ability to make distributions to our unitholders. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us.

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

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

- damage to our gathering and processing facilities, pipelines, related equipment and surrounding properties caused by tornadoes, floods, 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

other hazards, including those associated with high-sulfur content, or sour gas, that could also result in personal injury and loss of life, pollution and suspension of operations.

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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.

Due to our lack of asset diversification, adverse developments in our midstream operations would reduce our ability to make distributions to our unitholders.

We rely exclusively on the revenues generated from our midstream energy business, and as a result, our financial condition depends upon prices of, and continued demand for, natural gas and NGLs. Due to our lack of diversification in asset type, an adverse development in this business would have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets.

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

The markets to which the shippers on our Regency Intrastate Pipeline 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, that pipeline may refuse to accept all or a part of the natural gas scheduled for delivery to it. In those circumstances, we may be required to find alternative markets for that gas or to shut-in the producers of the non-conforming gas, potentially reducing our throughput volumes or revenues. Please see Item 1 Business Transportation Operations Interstate Pipeline Specifications.

Terrorist attacks, the threat of terrorist attacks, continued 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 threat of future terrorist attacks, on the energy transportation industry in general, and on us in particular, is not known at this time. Uncertainty surrounding continued 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.

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 and our ability to make cash distributions to you.

In addition, the construction of additions to our existing gathering 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 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.

A successful challenge to the rates we charge on Regency Intrastate Pipeline may reduce the amount of cash we generate.

To the extent our Regency Intrastate Pipeline transports natural gas in interstate commerce, the rates, terms and conditions of that transportation service are subject to regulation by the Federal Energy Regulatory Commission, or FERC, pursuant to Section 311 of the Natural Gas Policy Act of 1978, or NGPA, which regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of an interstate natural gas pipeline. Under Section 311, rates charged for transportation must be fair and equitable, and the FERC is required to approve the terms and conditions of the service. Rates established pursuant to Section 311 are generally analogous to the cost based rates FERC deems just and reasonable for interstate pipelines under the Natural Gas Act or NGA. FERC may therefore apply its NGA policies to determine costs that can be included in cost of service used to establish Section 311 rates. These rate policies include the new FERC policy on income tax allowance that permits interstate pipelines to include, as part of the cost of service, a full income tax allowance for all entities owning the utility asset provided such entities or individuals are subject to an actual or potential tax liability. If the Section 311 rates presently approved for Regency through May 2008 are successfully challenged in a complaint or after such date the FERC disallows the inclusion of costs in the cost of service, changes its regulations or policies, or establishes more onerous terms and conditions applicable to Section 311 service, this may adversely affect our business. Any reduction in our rates could have an adverse effect on our business, results of operations, financial condition and ability to pay distributions to you.

A change in the 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 Natural Gas Act of 1938, or 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, and market center promotion, indirectly affect intrastate markets. In recent years, FERC has pursued pro-competitive regulatory policies. We cannot assure you, however, that FERC will continue this approach as it considers 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 transmission service and federally unregulated gathering services is the subject of regular litigation at FERC and the courts and of policy discussions at FERC, so, in such circumstances, the classification and regulation of some of our gathering facilities or our intrastate transportation pipeline may be subject to change based on future determinations by FERC, and the courts or Congress. Such a change could result in increased regulation by FERC.

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. Please read Item 1 Business Regulation.

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. These include, for example, (1) the federal Clean Air Act and comparable state laws and regulations that impose obligations related to air emissions, (2) the federal Resource Conservation and Recovery Act, or RCRA, and comparable state laws that impose requirements for the discharge of waste from our facilities and (3) the Comprehensive Environmental, Response Compensation and Liability Act of 1980, or CERCLA, also known as Superfund, and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent waste for disposal.

For example, in November 2005, we settled with the Texas Commission on Environmental Quality, or TCEQ, a notice of enforcement relating to the operation of the Waha processing plant in 2001 before it was acquired by us. In connection with this settlement, we agreed to construct an acid reinjection well, in which we will reinject emitted gases from the plant at a cost of $6.0 million. Please read Item 1 Business Regulation.

Failure to comply with these laws and regulations or newly adopted laws or regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes, including the Clean Air Act, RCRA, CERCLA and the federal Water Pollution Control Act of 1972, also known as the Clean Water Act, and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to the necessity of handling of natural gas and other petroleum products, 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. Please read Item 1 Business Environmental Matters and Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Other Matters Environmental.

If we fail to develop or maintain an effective system of internal controls, we may not be able to report our financial results accurately or prevent fraud.

We became subject to the public reporting requirements of the Securities Exchange Act of 1934 on February 3, 2006. We produce our consolidated financial statements in accordance with the requirements of GAAP, but we do not become subject to certain of the internal controls standards applicable to most companies with publicly traded securities until after 2007. We may not currently meet all those standards. Effective internal controls are necessary for us to provide reliable financial reports to prevent fraud and to

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operate successfully as a publicly traded partnership. Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain adequate controls over our financial processes and reporting in the future, including compliance with the obligations under Section 404 of the Sarbanes-Oxley Act of 2002, which we refer to as Section 404. For example, Section 404 will require us, among other things, annually to review and report on, and our independent registered public accounting firm to attest to, our internal control over financial reporting. We must comply with Section 404 for our fiscal year ending December 31, 2007. Any failure to develop or maintain effective controls or difficulties encountered in their implementation or other effective improvement of our internal controls could harm our operating results or cause us to fail to meet our reporting obligations. Given the difficulties inherent in the design and operation of internal controls over financial reporting, we can provide no assurance as to our conclusions, or those of our independent registered public accounting firm, regarding the effectiveness of our internal controls. Ineffective internal controls subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business and would likely have a negative effect on the trading price of our common units. See Item 9A Controls and Procedures.

Risks Inherent in an Investment in Us

The HM Capital Investors own a 60.3% limited partner interest in us and control our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner has conflicts of interest and limited fiduciary duties, which may permit it to favor its own interests to your detriment.

The HM Capital Investors own a 60.3% limited partner interest in us and control our general partner. 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 (who together own an economic interest in our general partner of 8.4%) have a fiduciary duty to manage our general partner in a manner beneficial to its owners, the HM Capital Investors. Conflicts of interest may arise between the HM Capital Investors and their affiliates, including our general partner, on the one hand, and us and our unitholders, 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 the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires the HM Capital Investors or their affiliates 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 the HM Capital Investors, in resolving conflicts of interest;
- the HM Capital Investors and their affiliates may engage in competition with us;
- our general partner has limited its liability and reduced its fiduciary duties, and has also restricted the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional partnership securities, and reserves, each of which can affect the amount of cash that is distributed to unitholders;
- our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is a maintenance capital expenditure, which reduces operating surplus, or growth capital expenditure, which does not, which determination can affect the amount of cash that is distributed to our unitholders and the ability of the subordinated units to convert to common units;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;

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our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates 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;

our general partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 80% of the common units;

our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and

our general partner decides whether to retain separate counsel, accountants, or others to perform services for us.

The HM Capital Investors and their affiliates may compete directly with us.

The HM Capital Investors and their affiliates are not prohibited from owning assets or engaging in businesses that compete directly or independently with us. In addition, the HM Capital Investors or their affiliates may acquire, construct or dispose of any additional midstream or other assets in the future, without any obligation to offer us the opportunity to purchase or construct or dispose of those assets.

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

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. Please read Item 13. Certain Relationships and Related Party Transactions. The reimbursement of expenses of our general partner and its affiliates could adversely affect our ability to pay cash distributions to you.

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

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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.

By purchasing a common unit, a common unitholder will become 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 did not elect our general partner or its board of directors and will 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 were 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. The vote of the holders of at least $66^{2}/3$ % of all outstanding units voting together as a single class is required to remove the general partner. Our general partner and its affiliates own 60.3% of the total of our common and subordinated units. Moreover, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on the common units will be extinguished. A removal of the general partner under these circumstances would adversely affect the common units by prematurely eliminating their distribution and liquidation preference over the subordinated units, which would otherwise have continued until we had met certain distribution and performance tests.

Our partnership agreement restricts the voting rights of those unitholders owning 20% 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% 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 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 Regency GP LLC with their own choices and to control the decisions taken by the board of directors and officers.

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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;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Our general partner has a limited call right that may require you to sell your units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% 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. Our general partner and its affiliates now own approximately 20.7% of the common units. At the end of the subordination period, assuming no additional issuances of common units, our general partner and its affiliates will own approximately 60.3% of the 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.

We will incur increased costs as a result of being a public company.

We have no significant history operating as a public company. As a public company, we incur significant legal, accounting and other expenses that we did not incur as a private company. In addition, the Sarbanes-Oxley Act of 2002, as well as rules subsequently implemented by the SEC and the stock exchanges and markets, have required changes in corporate governance practices of public companies. We expect these rules and regulations to increase our legal and financial compliance costs and to make activities more time-consuming and costly. For example, as a result of becoming a public company, we are required to have three independent directors, create additional board committees and adopt policies regarding internal controls and disclosure controls and procedures, including the preparation of reports on internal controls over financial reporting. In addition, we will incur additional costs associated with our public company reporting requirements. We are currently evaluating and monitoring developments with respect to these rules, and we estimate the amount of additional costs we may incur will be $2.5 million annually.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity-level taxation by individual states. If the Internal Revenue Service, or IRS, treats us as a corporation or we become subject to entity-level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to you.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We did not request, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35% and would likely pay state 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, our treatment 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 our common 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. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. If any of these states were to impose a tax on us, the cash available for distribution to you would be reduced. The 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 levels will be adjusted to reflect the impact of that law on us.

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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.

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, 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 foreign 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 benefits available to you. It also could affect the timing of these tax benefits 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.

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 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, and Colorado. Each of these states, other than Texas, currently imposes a personal income tax as well as an income tax on corporations and other entities. Texas imposes a franchise tax (which is based in part on net income) 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.

ITEM 1B. Unresolved Staff Comments. This item is not applicable to the registrant.

ITEM 2. Properties.

Substantially all of our pipelines, which are located in Texas, Louisiana, Oklahoma, Kansas and, to a minor extent, Colorado, 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. Title to substantially all our assets is subject to a first priority lien and security interest in favor of the lending banks under our credit facilities. 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.

Office Facilities

Our executive offices occupy one entire floor in an office building at 1700 Pacific Avenue, Dallas, Texas, under a lease that expires at the end of October 2008. We also maintain small regional offices located on leased premises in Shreveport, Louisiana; Tulsa, Oklahoma; and Midland and San Antonio, Texas. While we may require additional office space as our business expands, we believe that our existing facilities are adequate to meet our needs for the immediate future, and that additional facilities will be available on commercially reasonable terms as needed.

ITEM 3. Legal Proceedings.

The operations of our operating partnership, Regency Gas Services LP or RGS, and its subsidiaries 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 RGS nor any of its subsidiaries is, however, currently a party to any material legal proceedings. In addition, there are no material legal or governmental proceedings currently pending or, to our knowledge, threatened against RGS or any of its subsidiaries under any of the various environmental protection statutes to which it is subject. See, however, the discussion of the TCEQ NOE and the ODEQ NOV under Item 1 Business Environmental Matters TCEQ Notice of Enforcement and Item 1 Business Environmental Matters ODEQ Notice of Violation.

There are no material legal or governmental proceedings currently pending or, to our knowledge, threatened against the Partnership or any of its subsidiaries.

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.

PART II

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

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

Our common units were first offered and sold to the public on February 3, 2006. Our common units are listed on the NASDAQ National Market under the symbol RGNC . The following table sets forth, for the periods indicated, the high and low closing sales prices per common unit, as reported on the NASDAQ National Market. The quarterly cash distribution to be declared and paid with respect to the common units for the quarter ending March 31, 2006 will be declared and paid on or before May 15, 2006. As a consequence, no quarterly cash distribution has yet been declared or paid with respect to the common units.

	Price Range		
Period	High	Low	Cash Distribution
Fiscal Year 2006			
First Quarter (through March 15, 2006)*	$ 21.29	$ 19.47	**

* Trading in common units on the NASDAQ National Market commenced on February 3, 2006.

** The initial quarterly cash distribution is not due to be declared and paid until May 15, 2006.

As of March 15, 2006, the number of holders of record of the common units was 1. The holder of record is Cede & Co., the nominee for Depository Trust Company.

Cash Distribution Policy

We will distribute to our unitholders, on a quarterly basis, all of our available cash in the manner described below. Available cash generally means, for any quarter ending prior to liquidation, all cash on hand at the end of that quarter less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the general partner to:

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

In addition to distributions on its 2% 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 our partnership agreement. Under the quarterly incentive distribution provisions, our general partner is entitled, without duplication, to 15% of amounts we distribute in excess of $0.4025 per unit, 25% of the amounts we distribute in excess of $0.4375 per unit and 50% of amounts we distribute in excess of $0.5250 per unit after each unitholder has received a total of $0.5250 per unit. We have not paid the general partner any incentive distributions in 2005.

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 Third Amended and Restated Credit Agreement.

Recent Sales of Unregistered Securities

On September 8, 2005, in connection with our formation we issued (i) to our general partner, Regency GP LP, its 2% general partner interest in us for $20 and (ii) to Regency Acquisition LLC its 98% limited partner interest in us for $980. As an integral part of the reorganization of RGS in connection with our initial public offering, we issued (i) 5,353,896 common units and 19,103,896 subordinated units to Regency Acquisition LP, successor to Regency Acquisition LLC, in exchange for certain equity interests in RGS and its general partner and (ii) incentive distribution rights (which represent the right to receive increasing percentages of quarterly distributions in excess of specified amounts) to our general partner in exchange for certain member interests. On March 8, 2006, we closed the sale of an additional 1,400,000 common units at a price of $20 per unit as the underwriters exercised their over allotment option in part. The net proceeds from the sale were used by us to redeem an equivalent number of common units held by Regency Acquisition LP for the benefit of the HM Capital Investors. The common and subordinated units were distributed by Regency Acquisition LP to its parent partnership which then further distributed an aggregate of 457,871 common units and 2,212,279 subordinated units to two directors and seven officers of the Managing GP upon their exchange of certain equity interests in that partnership. 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 securities within the past three years.

Use of Proceeds

In connection with the offering and sale by us of 13,750,000 common units on February 3, 2006 pursuant to our initial public offering of securities, we received net proceeds of approximately $257.0 million, after deducting underwriting discounts, fees and commissions but before paying estimated offering expenses. Approximately $48.0 million of the net proceeds was used to replenish our working capital as described below. We used the aggregate net proceeds of this offering:

- To replenish all, or approximately $48.0 million, of the working capital, or 18.7% of the net proceeds, $37.0 million of which was used to repay working capital borrowings under the revolving portion of our second amended and restated credit facility, that was distributed to the HM Capital Investors by RGS, immediately prior to consummation of the offering and the related formation transactions;

- to distribute approximately $195.5 million, or 76.1% of net proceeds, to the HM Capital Investors for reimbursement of capital expenditures comprising most of the initial investment by the HM Capital Investors in Regency Gas Services LLC;

- to pay $9.0 million, or 3.5% of net proceeds, to an affiliate of HM Capital as consideration for the termination of ten-year financial advisory and monitoring and oversight agreements between the affiliate of HM Capital and us; and

- to pay approximately $4.5 million, or 1.8% of net proceeds, of expenses associated with the offering and related formation transactions.

The HM Capital Investors realized approximately $243.5 million as a result of distributions made by us in connection with the offering, including the $48.0 million of working capital distributed to them

immediately prior to the consummation of the offering. This represented approximately 94.7% of the net proceeds from the offering. In addition, an affiliate of HM Capital received $9.0 million in connection with the termination of the financial advisory and monitoring and oversight agreements with us.

Borrowings being repaid under the revolving portion of our second amended and restated credit facility were incurred temporarily to finance working capital. Those borrowings under the revolving portion of our second amended and restated credit facility bore interest at the annual rate of 8.5% and would otherwise have matured on June 1, 2010. Affiliates of UBS Securities LLC, Wachovia Capital Markets, LLC and KeyBanc Capital Markets, a Division of McDonald Investments Inc., are lenders under our second amended and restated credit facility.

In early March, the underwriters of our initial public offering exercised in part their option to purchase additional common units pursuant to the underwriting agreement by purchasing 1,400,000 common units for $28.0 million ($26.2 million net to the Partnership). On March 8, 2006, we closed the sale of the additional 1,400,000 common units at a price of $20 per unit as the underwriters exercised their over allotment option in part. The net proceeds from the sale were used by us to redeem an equivalent number of common units held by Regency Acquisition LP for the benefit of the HM Capital Investors.

Equity Compensation Plan Information as of December 31, 2005

	(a)	(b)	(c)
Plan Category	**Number of securities to be issued upon exercise of outstanding options, warrants and rights**	**Weighted-average exercise price of outstanding options, warrants and rights**	**Number of securities remaining available for future issuance under equity compensation plans (excluding securities reported in column (a))**
Equity compensation plans approved by security holders	0	n/a	0
Equity compensation plans not approved by security holders	0	n/a	2,865,584
Total	0	n/a	2,865,584

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ITEM 6. Selected Financial Data

The following table shows selected financial data of our predecessors, Regency Gas Services LLC (Predecessor) and Regency LLC Predecessor. Our results of operations for the periods presented below may not be comparable, either from period to period or going forward, for the following reasons:

Regency LLC Predecessor was formed on April 2, 2003 and commenced operations on June 2, 2003 with the acquisition of certain natural gas gathering, processing and transportation assets from subsidiaries of El Paso Corporation. As a result, we do not have any financial results for periods prior to April 2, 2003 and our results of operations for the period ended December 31, 2003 includes only seven months of financial results.

On March 1, 2004, Regency LLC Predecessor acquired certain natural gas gathering and processing assets from Duke Energy Field Services, LP. As a result, our historical financial results for the periods prior to March 1, 2004 do not include the financial results from the operation of these assets.

In connection with the acquisition of Regency Gas Services LLC by the HM Capital Investors on December 1, 2004, the purchase price was pushed-down to the financial statements of Regency Gas Services LLC. As a result of this push-down accounting, the book basis of our assets was increased to reflect the purchase price, which had the effect of increasing our depreciation and amortization expense. Also, the increased amount of debt we incurred in connection with the acquisition increased our interest expense subsequent to December 1, 2004.

After our acquisition by the HM Capital Investors, we initiated a risk management program comprised of commodity swaps and crude oil puts that we accounted for using mark-to-market accounting from December 2004 through June 2005. Under mark-to market accounting, changes in the fair value of these instruments are recorded in earnings. On July 1, 2005 we implemented hedge accounting for our derivative financial instruments that qualified, in accordance with Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities. Changes in the fair value of these qualifying instruments, to the extent they are effective, are recorded in Other Comprehensive Income.

In response to transmission capacity constraints in north Louisiana, we significantly expanded and extended our pipeline assets in this region, increasing our capacity to 800 MMcf/d from 200 MMcf/d and increasing the length of the pipeline to 320 miles from 200 miles. The total cost of the project, which was completed in December 2005, is approximately $157.0 million.

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

The selected financial data for the year ended December 31, 2005 and the period from acquisition date (December 1, 2004) to December 31, 2004 are derived from the audited financial statements of the Predecessor. The selected financial data for the period from January 1, 2004 to November 30, 2004 and the period from inception (April 2, 2003) to December 31, 2003 are derived from the audited financial statements of Regency LLC Predecessor.

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The following table includes the non-GAAP financial measures EBITDA and total segment margin. We define EBITDA as net income plus interest expense, provision for income taxes and depreciation and amortization expense. We define total segment margin as total revenue, including service fees, less cost of gas and liquids and other cost of sales. For a reconciliation of EBITDA and total segment margin to their most directly comparable financial measures calculated and presented in accordance with GAAP (accounting principles generally accepted in the United States), please read Non-GAAP Financial Measures.

	Regency Gas Services LLC		Regency LLC Predecessor	
	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	Period from Inception (April 2, 2003) to December 31, 2003
	($ in thousands)			
Statement of Operations Data:				
Total revenue (1)	$ 692,603	$ 47,841	$ 432,321	$ 186,533
Expense				
Total cost of sales	620,751	40,986	362,762	163,461
Operating expenses	21,812	1,819	17,786	7,012
General and administrative	14,412	638	6,571	2,651
Transaction expenses			7,003	724
Depreciation and amortization	22,010	1,613	10,129	4,324
Total operating expenses	678,985	45,056	404,251	178,172
Operating income	13,618	2,785	28,070	8,361
Other income and deductions				
Interest expense, net	(17,432)	(1,335)	(5,097)	(2,392)
Loss on debt refinancing	(8,480)		(3,022)	
Other income and deductions, net	338	14	186	205
Total other income and deductions	(25,574)	(1,321)	(7,933)	(2,187)
Net (loss) income from continuing operations	(11,956)	1,464	20,137	6,174
Discontinued operations	732		(121)	
Net (loss) income	$ (11,224)	$ 1,464	$ 20,016	$ 6,174
Balance Sheet Data (at period end):				
Property, plant and equipment, net	$ 480,583	$ 328,348		$ 118,986
Total assets	654,324	486,489		164,330
Long-term debt	358,350	250,000		66,600
Member interest	169,778	176,964		59,856
Cash Flow Data:				

Net cash flows provided by (used in):				
Operating activities	$ 31,021	$ (4,930)	$ 32,401	$ 6,494
Investing activities	(150,195)	(129,947)	(84,721)	(123,165)
Financing activities	119,571	132,515	56,380	118,245
Other Financial Data:				
Total segment margin(1)	$ 71,852	$ 6,855	$ 69,559	$ 23,072
EBITDA(1)	28,218	4,412	35,242	12,890
Maintenance capital expenditures	7,817	358	5,548	1,633
Segment Financial and Operating Data:				
Gathering and Processing Segment:				
Financial data:				
Segment margin(1)	$ 56,179	$ 6,247	$ 61,347	$ 18,805
Segment operating expenses	19,883	1,655	16,230	6,131
Operating data:				
Natural gas throughput (thousand MMBtu/d)	308	315	303	211
NGL gross production (Bbls/d)	14,312	15,675	14,487	9,434
Transportation Segment:				
Financial data:				
Segment margin	$ 15,672	$ 608	$ 8,212	$ 4,268
Segment operating expenses	1,929	164	1,556	881
Operating data:				
Throughput (thousand MMBtu/d)	258	162	192	212

(1) Includes $0.3 million of unrealized gains on hedging transactions for the one month ended December 31, 2004, $9.5 million of unrealized losses on hedging transactions and $2.0 million of put option expiration for the year ended December 31, 2005.

Non-GAAP Financial Measures

We include in this Form 10-K 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;
- 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 is the starting point in determining cash available for distribution, which is an important measure for a publicly traded master limited partnership. Cash available for distribution will be fully addressed in the first quarter 2006 report on Form 10-Q.

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 in measuring 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. Management analyzes these other elements separately. 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 and other cost of sales. 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 segment margin is an important measure because it is directly related to our volumes and commodity price changes. Operating 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 our operating 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 operating expenses from total revenues in calculating segment margin because we separately evaluate commodity volume and price changes in 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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The following table presents a reconciliation of EBITDA and total segment margin to the most directly comparable GAAP financial measures, net income and net cash flows provided by (used in) operating activities.

	Regency Gas Services LLC		Regency LLC Predecessor	
	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	Period from Inception (April 2, 2003) to December 31, 2003
	($ 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	$ 31,021	$ (4,930)	$ 32,401	$ 6,494
Add (deduct):				
Depreciation and amortization	(23,092)	(1,745)	(10,461)	(4,658)
Loss on debt refinancing	(8,480)		(3,022)	
Risk management portfolio value changes	(11,191)	322		
Gain on the sale of Regency Gas Treating LP assets	626			
Gain on the sale of NGL line pack	628			
Accounts receivable	29,567	(2,583)	20,408	31,390
Advances to affiliates			(576)	576
Other current assets	1,237	2,430	1,169	1,070
Accounts payable and accrued liabilities	(32,722)	155	(18,122)	(26,880)
Accrued taxes payable	(806)	921	(1,475)	(906)
Interest payable	(67)	541	(398)	(143)
Distributions payable			69	(68)
Other current liabilities	(1,208)	(293)	(173)	(706)
Other assets	3,263	6,646	196	5
Net (loss) income	$ (11,224)	$ 1,464	$ 20,016	$ 6,174
Add:				
Interest expense, net	17,432	1,335	5,097	2,392
Depreciation and amortization	22,010	1,613	10,129	4,324
EBITDA(1)	$ 28,218	$ 4,412	$ 35,242	$ 12,890
Reconciliation of total segment margin to net (loss) income				

Net (loss) income	$ (11,224)	$ 1,464	$ 20,016	$ 6,174
Add (deduct):				
Operating expenses	21,812	1,819	17,786	7,012
General and administrative	14,412	638	6,571	2,651
Transaction expenses			7,003	724
Depreciation and amortization	22,010	1,613	10,129	4,324
Interest expense, net	17,432	1,335	5,097	2,392
Loss on debt refinancing	8,480		3,022	
Other income and deductions, net	(338)	(14)	(186)	(205)
Discontinued operations	(732)		121	
Total segment margin(1)	$ 71,852	$ 6,855	$ 69,559	$ 23,072

(1) Includes $0.3 million of unrealized gains on hedging transactions for the one month ended December 31, 2004, $9.5 million of unrealized losses on hedging transactions and $2.0 million of put option expiration for the year ended December 31, 2005.

ITEM 7. Management s Discussion and Analysis of Financial Condition and Results of Operation

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 Delaware limited partnership formed to capitalize on opportunities in the midstream sector of the natural gas industry. We own and operate five major natural gas gathering systems and four active processing plants in north Louisiana, west Texas and the mid-continent region of the United States, which includes Kansas, Oklahoma, Colorado, and the Texas Panhandle. We are engaged in gathering, processing, marketing and transporting natural gas and natural gas liquids, or NGLs. We connect natural gas wells of producers to our gathering systems through which we transport the natural gas to processing plants operated by us or by third parties. The processing plants separate NGLs from the natural gas. We then sell and deliver the natural gas and NGLs to a variety of markets.

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 factors affecting our profitability and review these measurements on a monthly basis for consistency and trend analysis. These measures include volumes, segment margin and operating 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 obtain new supplies is impacted by (1) the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to our pipelines, (2) our ability to compete for volumes from successful new wells in other areas and (3) 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 to pursue 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, which also include 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 natural gas. Our contract portfolio impacts our segment margin. See Our Operations for a discussion of our contract portfolio.

We calculate our Transportation segment margin as revenue minus the cost of natural gas that we purchase and transport. Revenue primarily includes sales of pipeline-quality natural gas and fees for the transportation of pipeline-quality natural gas. 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.

Operating Expenses. Operating expenses are 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 expenses. 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 operating expenses from total revenues in calculating segment margin because we separately evaluate commodity volume and price changes in segment margin.

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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 partners;

- 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.

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 is the starting point in determining cash available for distribution, which is an important measure for a publicly traded master limited partnership. Cash available for distribution will be fully addressed in the first quarter 2006 report on Form 10-Q.

Our Operations

We manage our business and analyze and report our results of operations through two business segments:

- Gathering and Processing in which 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 the NGLs and selling or delivering the pipeline-quality natural gas and NGLs to various markets and pipeline systems; and

- Transportation in which we deliver natural gas from northwest Louisiana to northeast Louisiana through our 320-mile Regency Intrastate Pipeline system, which has been significantly expanded and extended through our Regency Intrastate Enhancement Project. Our Transportation Segment includes certain marketing activities related to our transportation pipelines that are conducted by a separate subsidiary.

Gathering and Processing Segment

Results of operations from our Gathering and Processing segment are determined primarily by the volumes of natural gas 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, which we define as total revenues, including service fees, less the cost of natural gas and liquids and other cost of sales. 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 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.

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

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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.

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. For the year ended December 31, 2005, these arrangements accounted for about 25% of our natural gas volumes for this segment.

*Percent-of-*Proceeds Arrangements. Under these arrangements, we generally gather raw natural gas from producers at the wellhead, transport it through our gathering system, process it and sell the processed gas and NGLs at prices based on published index prices. In this type of arrangement, we retain the sales proceeds less amounts remitted to producers and the retained sales proceeds constitute our margin. These arrangements provide upside in high commodity price environments, but result in lower margins in low commodity price environments. Under these arrangements, our margins typically cannot be negative. We regard the margin from this type of arrangement as an important analytical measure of these arrangements. The price paid to producers is based on an agreed percentage of one of the following: (1) the actual sale proceeds; (2) the proceeds based on an index price; or (3) the proceeds from the sale of processed gas or NGLs or both. Under this type of arrangement, our margin correlates directly with the prices of natural gas and NGLs (although there is often a fee-based component to these contracts in addition to the commodity sensitive component). For the year ended December 31, 2005, these arrangements accounted for about 49% of our natural gas volumes for this segment.

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) provisions that require the keep-whole contract to convert to a fee-based arrangement if the NGLs have a lower value than their thermal equivalent in natural gas, (2) 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, (3) fixed cash fees for ancillary services, such as gathering, treating, and compression, or (4) the ability to bypass in unfavorable price environments. For the year ended December 31, 2005, these arrangements accounted for approximately 26% of our natural gas volumes for this segment.

An important aspect of our contract portfolio management strategy is to decrease our keep-whole contract risk exposure. Immediately following the acquisition of our mid-continent assets in 2003, we terminated our month-to-month keep-whole arrangements and replaced them with fee-based or percentage-of-proceeds agreements or variations thereof. In addition, we seek to replace our longer term keep-whole arrangements as they expire or whenever the opportunity presents itself. At the time of the acquisition of our mid-continent assets, approximately 71% of our natural gas volumes associated with those assets was subject to keep-whole arrangements. As of December 31, 2005, we had reduced that number to approximately 22% in the mid-continent region.

As part of our previously planned strategy, on August 1, 2005, we suspended operations at our Lakin natural gas processing plant, reserving the right to operate it intermittently. The natural gas that would have been processed at the Lakin plant is now processed at a third party processing plant for our account for a fee. Suspending the operations of the plant allowed us to renegotiate and replace certain unfavorable keep-whole processing arrangements covering natural gas processed at the plant with fee-based contracts. Additionally, by suspending the Lakin plant, we are able to avoid charges for transporting natural gas through a third party pipeline out of the tailgate of the plant. We expect to realize a net benefit to our cash flows and earnings from these changes in addition to a reduced risk portfolio. We are actively seeking to use the 80 MMcf/d of newly available processing capacity at the Lakin plant by attempting to contract for additional supply to the plant or by moving the plant to a new location.

In our Gathering and Processing segment, we are a seller of NGLs and are exposed to commodity price risk associated with movements in NGL prices. NGL prices have experienced volatility in recent years in response to changes in the supply and demand for NGLs and market uncertainty. In response to this volatility, we have, since the acquisition of Regency Gas Services LLC by HM Capital Investors, executed swap contracts settled against ethane, propane, butane and natural gasoline market prices, supplemented with crude oil put options (historically, changes in the prices of heavy NGLs, such as natural gasoline, have generally correlated with changes in the price of crude oil). As a result, we have hedged approximately 95% of our expected exposure to NGL prices in 2006, approximately 75% in 2007 and approximately 50% in 2008. We continually monitor our hedging and contract portfolio and expect to continue to adjust our hedge position as conditions warrant.

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 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.

Until recently, the NGLs produced by our processing plants were sold to third parties as mixed NGLs. In September 2005, we began delivering the mixed NGLs produced by our processing plants to operators of fractionation facilities for fractionation for our account. We then sell the individual components, such as ethane, propane and isobutane, directly to marketing companies, refineries and other wholesalers. We believe this marketing function will allow us to earn additional margins from the sale of the NGLs that otherwise would have been earned by the fractionator.

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 our 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 the outlet. In the latter case, we generally purchase pipeline-quality natural gas at a pipeline inlet price adjusted to reflect our transportation fee and we sell that natural gas at the pipeline outlet. The differential in the purchase price and the sale price contributes to our segment margin. 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. To the extent a sustained decline in commodity prices resulted 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. Our obligation to provide firm transportation service means that we are 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.

Interruptible Transportation. Our obligation to provide interruptible transportation service means that we are only obligated to transport natural gas nominated by the shipper 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 our transportation services under the terms of our contracts and under an operating statement that we have filed and maintain with FERC with respect to transportation authorized under section 311 of the Natural Gas Policy Act of 1978, or 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.

Enhancement Project. Portions of the Regency Intrastate Pipeline system have historically operated at full capacity and represented a significant constraint on the flow of natural gas from producing fields in north Louisiana to intrastate and interstate markets in northeast Louisiana. In response, we have completed a major expansion and extension of this system, which we refer to as the Regency Intrastate Enhancement Project. This project quadrupled the system s capacity from the capacity that existed prior to the commencement of the project.

The Regency Intrastate Enhancement Project was a multi-phase project designed to relieve bottlenecks on certain sections of the pipeline and to access new sources of supply and markets. We began planning this project in January 2005 and started construction in May 2005. We completed the project in December 2005. This project included the expansion of our existing Regency Intrastate Pipeline system and the addition of an 80-mile, 30-inch diameter pipeline extension to the Regency Intrastate Pipeline system supported by approximately 9,500 horsepower of additional compression. The project has extended our transportation services into additional major producing fields in north Louisiana, connected our system to additional pipelines in northeast Louisiana and has increased the capacity of the pipeline to 800 MMcf/d.

The total cost of this project is approximately $157.0 million. Our original estimate for this project was approximately $140.0 million. The excess of cost over our estimate includes $2.5 million of costs that we dispute and otherwise consists primarily of insufficient estimates of materials, right of way and legal expenditures, sales taxes and capitalized interest.

One of our motivations to enhance this pipeline was to enable our customers to reach markets offering more favorable prices by developing interconnects with other pipelines. As of December 31, 2005, the Regency Intrastate Pipeline system could deliver gas to two 250 MMcf/d interconnects. Since then, three additional interconnects have been completed: two 250 MMcf/d interconnections and a 500 MMcf/d interconnection.

The completion of the Regency Intrastate Enhancement Project enables us to provide transportation services from the three largest natural gas producing fields in Louisiana. Prior to the completion of the final phase of the project in December 2005, we were transporting approximately 265 MMcf/d under existing contracts. Through March 28, 2006, we have signed definitive agreements for 466,000 MMBtu/d of firm transportation on the Regency Intrastate Pipeline system and 404,000 MMBtu/d of interruptible transportation. We are engaged in discussions with other parties interested in utilizing the remaining firm system transportation capacity.

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 to be incorrect, our actual results may vary materially from our expected results.

Natural Gas Supply, Demand and Outlook. Natural gas continues to be a critical component of energy consumption in the United States. According to the Energy Information Administration, or EIA, total annual domestic consumption of natural gas is expected to increase from approximately 22.2 trillion cubic feet, or Tcf, in 2005 to approximately 25.9 Tcf in 2015, representing an average annual growth rate of approximately 1.7%. During the five years ending December 31, 2005, the United States has on average consumed approximately 22.4 Tcf per year, while total marketed domestic production averaged approximately 19.8 Tcf per year during the same period. The industrial and electricity generation sectors currently account for the largest usage of natural gas in the United States.

We believe that current natural gas prices and the existing strong demand for natural gas will continue to result in relatively high levels of natural gas-related drilling in the United States as producers seek to increase their level of natural gas production. Although the natural gas reserves in the United States have increased overall in recent years, a corresponding increase in production has not been realized. We believe that this lack of increased production is attributable to insufficient pipeline infrastructure, the continued depletion of existing wells and a tight labor and equipment market. We believe that an increase in United States natural gas production, additional sources of supply such as liquid natural gas, and imports of natural gas will be required for the natural gas industry to meet the expected increased demand for natural gas in the United States.

All of the areas in which we operate are experiencing significant drilling activity. Although we anticipate continued high levels of exploration and production activities in all of these areas, 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.

Gathering and Processing Segment Margins. For the year ended December 31, 2005, our overall portfolio of processing contracts reflected a net short position in natural gas of approximately 7,400 MMBtu/d (meaning that we were a net buyer of natural gas) and a net long position in NGLs of approximately 4,900 Bbls/d (meaning that we were a net seller of NGLs). As a result, during this period our segment margins were positively impacted to the extent the price of NGLs increased in relation to the price of natural gas and were adversely impacted to the extent the price of NGLs declined in relation to the price of natural gas. We refer to the price of NGLs in relation to the price of natural gas as the fractionation spread. Our contract portfolio performed well in response to favorable fractionation spreads during 2005.

In keeping with our strategy of reducing commodity price exposure, we have adjusted our contract portfolio through renegotiation of certain keep-whole contracts, including three large keep-whole contracts that were converted to fee contracts in August 2005, resulting in a shift of our overall natural gas position to a slightly long position going forward, while retaining a long physical NGL position. We believe that this adjusted portfolio effectively hedges our overall exposure to volatility in fractionation spreads. Our profitability is now positively impacted if natural gas or NGLs prices increase and negatively impacted if natural gas or NGLs prices decrease. The prices of natural gas and NGLs are volatile and beyond our control.

Impact of Interest Rates and Inflation. The credit markets recently have experienced 50-year record lows in interest rates. If the overall economy continues to strengthen, we believe that it is likely that monetary policy will tighten further, resulting in higher interest rates to counter possible inflation. Interest rates on future credit facilities and debt offerings could be 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 impact on our results of operations in 2003, 2004 or 2005. 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.

Formation, Acquisition and Asset Disposal History and Financial Statement Presentation

Our Formation of Regency Energy Partners LP and Our Initial Public Offering

We are a Delaware limited partnership formed in September 2005 to own and operate Regency Gas Services LLC. Prior to the completion of our initial public offering, Regency Gas Services LLC was owned by the HM Capital Investors. 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, in exchange for 5,353,896 common units, 19,103,896 subordinated units, the incentive distribution rights, a continuation of its 2% general partner interest in us, and a right to receive $195.5 million of cash proceeds from our initial public offering. The cash proceeds constituted a reimbursement of a corresponding amount of capital expenditures comprising most of the initial investment by the HM Capital Investors in Regency Gas Services LLC. In addition, approximately $48.0 million in cash and accounts receivable were distributed by Regency Gas Services LLC to Regency Acquisition LP and then to the HM Capital Investors immediately prior to the contribution of Regency Gas Services LLC to us. These current assets were replenished with proceeds from the offering.

On March 8, 2006, we closed the sale of an additional 1,400,000 common units at a price of $20 per unit as the underwriters exercised their over allotment option in part. The net proceeds from the sale were used by us to redeem an equivalent number of common units held by Regency Acquisition LP for the benefit of the HM Capital Investors.

We paid $9.0 million of the proceeds from our initial public offering to terminate our ten-year financial advisory, monitoring and oversight agreements with an affiliate of HM Capital. In the first quarter of 2006 we will expense these costs.

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 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. In our consolidated financial statements, Regency Gas Services LLC is designated as Predecessor for periods ended subsequent to December 1, 2004 and the Regency LLC Predecessor periods ended before December 1, 2004.

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 Assets

In June 2003, Regency Gas Services LLC acquired certain natural gas gathering, processing and transportation assets from subsidiaries of El Paso Corporation for approximately $119.5 million. The assets acquired consisted of gathering, processing and transportation assets located in north Louisiana and gathering and processing assets located in the mid-continent region of the United States and represent substantially all of our existing north Louisiana and mid-continent assets. At the time of the acquisition, the acquired gathering and transportation systems had an average expected remaining useful life of approximately 20 years and the processing plants had an average expected remaining useful life of approximately 15 years.

Prior to our acquisition of these assets, these assets were operated as components of El Paso s much larger midstream operations. Immediately following our acquisition of these assets, we changed the manner in which these assets were operated. In that regard, we initiated, and continue to implement, a strategy to reshape the revenue structure of the acquired assets to expand revenues, increase margins and decrease exposure to market volatility.

Acquisition of Duke Energy Field Services Assets

In March 2004, Regency Gas Services LLC acquired certain natural gas gathering and processing assets from Duke Energy Field Services, LP for approximately $67.3 million, including transactional costs. The assets acquired consisted of gathering and processing assets located in west Texas and represent substantially all of our existing west Texas assets.

Prior to our acquisition of these assets, these assets were operated as components of Duke Energy Field Services much larger midstream operations. As with the assets acquired from El Paso, immediately following our acquisition of these assets, we implemented significant operational changes designed to expand revenues, increase margins and limit exposure to market volatility. We promptly changed the manner in which pipeline-quality natural gas was marketed from these assets by extending contract terms.

Others

In April 2004, we completed the purchase of gas processing interests located in Louisiana and Texas from Cardinal Gas Services LLC (Cardinal) for $3.5 million in cash. In May 2005, we sold all of the assets acquired from Cardinal, together with certain related assets, for $6.0 million. After the allocation of $0.9 million of goodwill, the resulting gain was $0.6 million. We have treated these operations as a discontinued operation.

Items Impacting Comparability of Our Financial Results

Our historical results of operations for the periods presented may not be comparable, either from period to period or going forward, for the reasons described below:

Regency LLC Predecessor commenced operations in June 2003 with the acquisition of the El Paso assets. As a result, we do not have any material financial results for periods prior to June 2003 and our results of operations for the period ended December 31, 2003 includes only seven months of financial results.

Regency LLC Predecessor acquired the Duke Energy Field Services assets in March 2004. As a result, our financial results for periods prior to March 2004 do not include the financial results of the Duke Energy Field Services assets.

In connection with the acquisition of Regency Gas Services LLC by the HM Capital Investors on December 1, 2004, the purchase price was pushed-down to the financial statements of Regency Gas Services LLC. As a result of this push-down accounting, the book basis of our assets was increased to reflect the purchase price, which had the effect of increasing our depreciation and amortization expense. Also, the increased level of debt incurred in connection with the acquisition increased our interest expense subsequent to December 1, 2004.

We anticipate incurring approximately $2.5 million of additional general and administrative costs, including costs relating to operating as a separate publicly held entity, such as costs associated with annual and quarterly reporting, tax return and Schedule K-1 preparation and distribution, Sarbanes-Oxley compliance costs, independent auditor fees, investor relation expenses, registrar and transfer agent fees.

In December 2004 we undertook a hedging program as required by our credit facilities. Effective July 1, 2005 we designated certain commodity and interest rate swap instruments for hedge accounting treatment in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. For the periods from December 1, 2004 through June 30, 2005 unrealized and realized gains and losses on the commodity swaps were recorded in unrealized/realized gain (loss) from risk management activities in our statements of operations. For the six months ended June 30, 2005 unrealized gains and losses on the interest rate swap were recorded in interest expense, net. Effective July 1, 2005, to the extent the hedges are effective, any unrealized gains or losses on these instruments were recorded in other comprehensive income (loss) during the lives of the instruments, which we believe will lead to financial results that are not comparable for the affected periods.

We completed a major enhancement of our Regency Intrastate Pipeline system and the pipeline, as expanded and extended, began operations on December 28, 2005. As of March 30, 2006 we were transporting approximately 450,000 MMBtu/d of natural gas.

Critical Accounting Policies and Estimates

Conformity with accounting principles generally accepted in the United States 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. 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 sales on the gross basis for those transactions where we act as the principal and take title to gas that is purchased 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.

Prior to March 2006, we recorded the monthly results of operations using actual results which included settling most of our volumes with producers, shippers and customers around the 25th of the month following the production month. This process resulted in a delay in reporting results. To conform to industry practice, we are implementing a closing process in March 2006 that eliminates the reporting lag. Prior to the settlement date, we will record actual operating data as available, such as actual operating and maintenance and other expenses. For total segment margin, we will estimate settlements using actual pricing and nominated volumes. In the subsequent production month, we will reconcile the estimates to the actual results and record the difference which is not expected to be material. The new process expedites financial reporting and conforms to industry practice.

Risk Management Activities. In order to protect ourselves from commodity and interest rate 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 four 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. For example, we recently executed commodity price swaps on approximately 50% of our expected net NGL exposure in 2008.

From the inception of our hedging program in December 2004 through June 30, 2005, we used mark-to-market accounting for our commodity and interest rate swaps as well as for crude oil puts. For the one month ending December 31, 2004, the amount of net realized and unrealized gains was $0.3 million. For the year ended December 31, 2005, we incurred $22.2 million of realized and unrealized net losses, $13.0 million of which was realized and $9.2 million of which was unrealized. The unrealized loss of $9.2 million is comprised of $9.5 million of net losses related to commodity hedges that are reflected in operating revenues and $0.3 million of net gains related to interest rate hedges that are reflected in interest expense, net. We record realized gains and losses on hedge instruments monthly based upon the cash settlements and the expiration of option premiums. The settlement amounts vary due to the volatility in the commodity market prices throughout each month. We also record unrealized gains and losses monthly based upon the future value of the hedges through their expiration dates. The expiration dates vary but are currently no later than December 2008. We monitor and review hedging positions regularly. Effective July 1, 2005, we elected to use hedge accounting for the swap contracts. We believe that the prospective application of cash flow hedge accounting for the swap transactions will mitigate the volatility in our earnings.

Purchase Accounting. On December 1, 2004, we were acquired by the HM Capital Investors. We made various assumptions in determining the fair values of acquired assets and liabilities. In order to allocate the purchase price to the business units, we developed fair value models with the assistance of outside consultants. These fair value models applied discounted cash flow approaches to expected future operating results, considering expected growth rates, development opportunities, and future pricing assumptions. An economic value was determined for each business unit. The total economic value was equal to the purchase price. We then determined the fair value of the fixed assets based on estimates of replacement costs. We identified intangible assets related to licenses and permits, and renegotiated customer contracts and assigned a fair value of $18.5 million. We made assumptions regarding the period of time it would take to replace these permits. We assigned value using a lost profits model over that period of time necessary to replace the permits. The customer contracts were valued using a discounted cash flow model. We determined liabilities assumed based on their expected future cash outflows. We recorded goodwill of $58.5 million as the excess of the cost of each business unit over the sum of amounts assigned to the tangible assets, financial assets, and separately recognized intangible assets acquired less liabilities assumed of the business unit.

Depreciation Expense and Cost Capitalization Policies. Our assets consist primarily of natural gas gathering pipelines, processing plants, and transmission pipeline. 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. We capitalized $2.6 million of interest related to the Regency Intrastate Enhancement Project. These costs are then expensed over the life of the constructed asset through the recording of depreciation expense. Under certain contractual circumstances our gathering and transmission system includes natural gas or NGL line pack, which is a non-depreciable asset.

As discussed in the Notes to the Consolidated Financial Statements, depreciation of our assets is generally computed using the straight-line method over the estimated useful life of the assets. The costs of renewals and betterments that extend the useful life of property, plant and equipment are also capitalized. Certain assets such as land, NGL line pack and natural gas line pack are non-depreciable. The costs of repairs, replacements and maintenance projects are expensed as incurred.

The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets. As circumstances warrant, depreciation estimates are reviewed 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.

Environmental Remediation. Current accounting guidelines require us to recognize a liability and expense associated with environmental remediation if (i) government agencies mandate such activities or one of our properties were added to the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, database, (ii) the existence of a liability is probable and (iii) the amount can be reasonably estimated. To date, we have not recorded any liability for remediation expenses and we do not believe that any significant liability currently exists. If governmental regulations change, we could be required to incur remediation costs that might have a material impact on our profitability.

We account for our asset retirement obligations in accordance with Statement of Financial Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations and FIN 47 Accounting for Conditional Asset Retirement Obligations. These accounting standards require us to recognize on the balance sheet the net present value of any legally binding obligation to remove or remediate the physical assets that we retire from service, as well as any similar obligations for which the timing and/or method of settlement are conditional on a future event that may or may not be within our control. While we are obligated under contractual agreements to remove certain facilities upon their retirement, we are unable to reasonably determine the fair value of any asset retirement obligations as of December 31, 2005 and 2004 because the settlement dates, or ranges thereof, were indeterminable and could range up to ninety-six years, and the undiscounted amounts are immaterial. An asset retirement obligation will be recorded in the periods wherein we can reasonably determine the settlement dates.

Equity Based Compensation. In December 2005, the compensation committee of the board of directors of our Managing GP approved a long-term incentive plan, or LTIP, for our employees, directors and consultants. On February 3, 2006 awards were granted in connection with the consummation of our initial public offering. The initial grant included a total of 262,500 restricted common units and 599,300 common unit options with grant-date fair values of $20 per unit and $1.15 per option. In the aggregate, these awards represent 861,800 potential common units. The options were valued with the Black-Scholes Option Pricing Model under the following assumptions: 15% volatility in the unit price, a ten year term, a strike price equal to the initial public offering price of $20 per unit, a distribution yield of 7%, and an average exercise of the options of four years after vesting is complete. The assumption that participants will, on average, exercise their options four years from the vesting date is based on the average of the mid-points from vesting to expiration of the options.

Subsequent to the initial grant, we awarded 100,000 restricted common units and 58,000 common unit options. The awards were issued at weighted average grant date fair values of $20.51 per restricted common unit and $1.20 per unit option. In aggregate, these awards represent 158,000 potential common units. The terms of the awards and the valuation assumptions are identical to those in the initial grant, adjusted for the differences in the unit prices and grant dates.

A total of 2,865,584 common units have been authorized for delivery under the LTIP. All LTIP awards are subject to a three year vesting period. For each year completed, one-third of the award will vest. The options have a maximum contractual term, expiring ten years after the grant date.

We will make the same distributions to holders of non-vested restricted common units as those paid to common unit holders. Upon the vesting of the restricted common units and the exercise of the common unit options, we intend to settle these obligations with common units. Accordingly, we expect to recognize an aggregate of $7.7 million of compensation expense related to the initial grants under LTIP, or $2.6 million for each of the three years of the vesting period for such grants. We adopted SFAS 123(R) Share-Based Payment in the first quarter of 2006 which had no impact to us as no LTIP awards were outstanding during 2005.

Senior members of management and outside directors who held Class B or Class D units of HMTF Regency, L.P. entered into exchange agreements in connection with the consummation of the Partnership s initial public offering whereby they exchanged their Class B or Class D units for common and subordinated units in Regency Energy Partners LP and an interest in Regency GP LLC. We have evaluated the impact of the exchange agreements and will not record a material amount of compensation expense related to this exchange.

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Results of Operations

Year Ended December 31, 2005 vs. Combined Year Ended December 31, 2004

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

	Predecessor	Regency LLC Predecessor		
	Year Ended December 31,			
	2005	2004(d)	$ Change	% Change
		(combined)		
	($ in millions)			
Revenues(a)	$ 692.6	$ 480.2	$ 212.4	44%
Cost of sales	620.7	403.8	216.9	54
Total segment margin(b)	71.9	76.4	(4.5)	(6)
Operating expenses	21.8	19.6	2.2	11
General and administrative	14.4	7.2	7.2	100
Transaction expenses	-	7.0	(7.0)	(100)
Depreciation and amortization	22.0	11.7	10.3	88
Operating income	13.7	30.9	(17.2)	(56)
Interest expense, net	(17.4)	(6.5)	(10.9)	168
Loss on debt refinancing	(8.5)	(3.0)	(5.5)	183
Other income and deductions, net	0.3	0.2	0.1	50
Net (loss) income from continuing operations	(11.9)	21.6	(33.5)	(155)
Discontinued operations	0.7	(0.1)	0.8	(800)
Net (loss) income	$ (11.2)	$ 21.5	$ (32.7)	(152)%
System inlet volumes (MMBtu/d)(c)	565,991	493,956	72,035.0	15%
Processing volumes (MMBtu/d)	220,500	271,555	(51,055.0)	(19)

(a) Includes $0.3 million of net unrealized gains on hedging transactions for the year ended December 31, 2004. Includes $9.5 million of net unrealized losses on hedging transactions and $2.0 million of put option expiration for the year ended December 31, 2005.

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

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

(d) We combined the results of operations for the period from acquisition date (December 1, 2004) of the Predecessor and the period from January 1, 2004 to November 30, 2004 of the Regency LLC Predecessor to provide an annual reporting period for a more meaningful comparison versus the year ended December 31, 2005. To the extent operations for the 2005 period are not comparable to the combined 2004 period; we have disclosed such differences in the discussion of results of operations. See the separate discussion of the one month ended December 31, 2004.

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

	Predecessor	Regency LLC Predecessor		
	Year Ended December 31,			
	2005	2004(b)	$ Change	% Change
		(combined)		
	($ in millions)			
Segment Financial and Operating Data:				
Gathering and Processing Segment				
Financial data:				
Segment Margin(a)	$ 56.2	$ 67.6	$ (11.4)	(17)%
Operating expenses	19.9	17.9	2.0	11
Operating data:				
Throughput (thousand MMBtu/d)	308	304	4.0	1
NGL gross production (Bbls/d)	14,312	14,588	(276.0)	(2)
Transportation Segment				
Financial data:				
Segment Margin	$ 15.7	$ 8.8	$ 6.9	78%
Operating expenses	1.9	1.7	0.2	12
Operating data:				
Throughput (thousand MMBtu/d)	258	190	68.0	36

(a) Includes $0.3 million of net unrealized gains on hedging transactions for the year ended December 31, 2004. Includes $9.5 million of net unrealized losses on hedging transactions and $2.0 million of put option expiration for the year ended December 31, 2005.

(b) We combined the results of operations for the period from acquisition date (December 1, 2004) of the Predecessor and the period from January 1, 2004 to November 30, 2004 of the Regency LLC Predecessor to provide an annual reporting period for a more meaningful comparison versus the year ended December 31, 2005. To the extent operations for the 2005 period are not comparable to the combined 2004 period, we have disclosed such differences in the discussion of results of operations. See the separate discussion of the one month ended December 31, 2004.

Net Income. Net income for the year ended December 31, 2005 decreased $32.7 million compared with the combined year ended December 31, 2004. Interest expense, net increased $10.9 million primarily due to higher net interest expense related to debt incurred to fund the HM Capital Transaction. Depreciation and amortization expense increased $10.3 million primarily due to our higher depreciable basis following purchase accounting for the HM Capital Transaction. In the year ended December 31, 2005 we wrote off $8.5 million of debt issuance costs (consisting of $5.8 million of unamortized debt issuance costs, $1.9 million of costs incurred in July 2005 and $0.8 million of costs incurred in November 2005 in connection with amendments to our credit facilities). In the combined year ended December 31, 2004, we wrote off $3.0 million of unamortized debt issuance costs. The decrease in net income also included a reduction in total segment margin of $4.5 million, which included a $9.5 million net unrealized loss and a $12.7 million realized loss from risk management activities partially offset by a positive price variance in our Gathering and Processing Segment and improved segment margin in our Transmission Segment. General and administrative expense increased $7.2 million primarily as a result of higher employee-related expenses. Operating expenses increased $2.2 million primarily due to our west Texas facilities operating twelve months in 2005 versus ten months in 2004 and higher taxes, other than income. In the combined year ended 2004, the Regency LLC Predecessor incurred transaction expenses of $7.0 million related to certain non-recurring costs associated with the HM Capital transaction.

During the year ended December 31, 2005, we realized losses of $12.7 million on risk management activities. This loss consists of $10.8 million of swap settlements and $1.9 million of premiums associated with expired crude put options which were paid in a prior period. As noted below, these amounts were offset by a positive price variance of $10.8 million, demonstrating the effectiveness of our hedging program with respect to stabilizing the cash generated by the sale of our NGLs.

Total Segment Margin. Total segment margin for the year ended December 31, 2005 decreased to $71.9 million from $76.4 million for the combined year ended December 31, 2004, representing a 6% decline. Non-cash losses reduced total segment margin by $11.5 million. These non-cash losses were caused by the net change in the fair value of derivative contracts during such time as the contracts were not designated as hedges in 2005 and the expiration of certain crude oil put options. This decrease was offset in part by increased pipeline throughput volumes, which produced additional margin of $7.2 million. Pricing effects were negligible, as $10.8 million of increased total segment margin attributable to commodity prices was offset by $10.8 million in cash hedge settlements demonstrating the effectiveness of our hedging program. Please read Critical Accounting Policies and Estimates for a detailed discussion of this matter.

Segment margin for the Gathering and Processing Segment for the year ended December 31, 2005 decreased to $56.2 million from $67.6 million for the combined year ended December 31, 2004, representing a 17% decline. The elements driving this reduction in segment margin are as follows:

Pricing effects were negligible, as $10.8 million of increased segment margin attributable to higher commodity prices was offset by $10.8 million in cash hedge settlements,

$0.3 million of increase segment margin attributable to increased pipeline throughput volumes,

$11.5 million of decreased segment margin attributable to non-cash losses reflecting the net change in the fair value of derivatives contracts during the first six months of 2005 and the expiration of certain crude oil put option in 2005, and

Segment margin in 2004 was increased by $0.3 million of non-cash gains reflecting the net change in the fair value of derivative contracts for the period.

Segment margin for the Transportation segment for the year ended December 31, 2005 increased to $15.7 million from $8.8 million for the comparable combined period in 2004, a 78% increase. The increase was attributable to increased throughputs across the system in 2005.

Operating Expenses. Operating expenses for the year ended December 31, 2005 increased to $21.8 million from $19.6 million for the combined year ended December 31, 2004, representing a 11% increase. This increase resulted in part from higher operating expenses of $1.0 million associated with our west Texas assets in the Gathering and Processing Segment for the full year ended December 31, 2005 as compared to ten months in 2004. Higher taxes, other than income, primarily property taxes in the mid-continent region within the Gathering and Processing Segment, resulted in an increase of $0.8 million. Also contributing to the increase in operating expenses were higher materials and parts expense of $0.7 million in the Transportation Segment and the remainder of the Gathering and Processing segment. These increases were partially offset by lower employee costs and rental expense of $0.3 million in the mid-continent region of the Gathering and Processing Segment related to our previously planned shut down of our Lakin gas processing plant. See the discussion on *Gathering and Processing Segment* for additional information regarding the Lakin shut down.

General and Administrative. General and administrative expense increased to $14.4 million in the year ended December 31, 2005 from $7.2 million for the combined year ended December 31, 2004. This increase was primarily attributable to higher employee-related expenses of $3.1 million, including higher salary expense associated with increased headcount and bonus accruals. Also contributing to the increase were increased professional and consulting expenses of $2.9 million, consisting primarily of legal fees for regulatory and contract related matters, business development expenses and consulting fees for Sarbanes-Oxley compliance support. Further contributing to the increase were higher management fees of

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$0.7 million, resulting from our relationship with HM Capital, increased insurance costs of $0.2 million and various other general and administrative expenses of $0.3 million.

Transaction Expenses. Regency LLC Predecessor incurred non-recurring expenses related to the HM Capital transaction in the amount of $7.0 million in 2004. These expenses were comprised of compensation, legal and other expenses and were paid prior to the HM Capital transaction.

Depreciation and Amortization. Depreciation and amortization increased to $22.0 million in the year ended December 31, 2005 from $11.7 million for the combined year ended December 31, 2004, representing an 88% increase. Depreciation expense increased $8.6 million primarily due to the acquisition of Regency Gas Services LLC by the HM Capital Investors in December 2004, which increased the book basis of our depreciable assets to their fair market value. Also contributing to the increase was the amortization of identifiable intangible assets of $1.7 million in the 2005 period related to purchase accounting following the HM Capital Transaction.

Interest Expense, Net. Interest expense, net increased $10.9 million, or 168%, in the year ended December 31, 2005 compared to the combined year ended December 31, 2004 due to higher net interest expense of $10.1 million, primarily related to debt incurred to fund the HM Capital Transaction, and increased amortization of debt issuance costs of $0.8 million.

Loss on Debt Refinancing. In the year ended December 31, 2005 and combined year ended December 31, 2004, we wrote-off $8.5 million and $3.0 million, respectively, of debt refinancing costs related to our amended credit facilities in accordance with EITF 96-19, Debtor s Accounting for a Modification or Exchange of Debt Instruments. The $8.5 million write-off consisted of $5.8 million of unamortized debt issuance costs, $1.9 million of costs incurred in July 2005 and $0.8 million of costs incurred in November 2005 in connection with amendments to our credit facilities. The write-off for the combined year ended December 31, 2004 consisted of unamortized debt issuance costs.

Federal Income Tax. As a pass-through entity, we are not subject to federal income taxes. The liability for federal income taxes associated with income produced by our business is passed through to and recognized by entities that are investors on our indirect parent.

Discontinued Operations. On April 1, 2004, we completed the purchase of natural gas processing and treating interests located in Louisiana and Texas from Cardinal for $3.5 million. On May 2, 2005, we sold all of the assets acquired from Cardinal, together with certain related assets, for $6.0 million. The results of these operations are presented as discontinued operations, and we recorded a gain on the sale of $0.6 million during the year ended December 31, 2005.

See Note 2 to the accompanying consolidated financial statements and Formation, Acquisition and Asset Disposal History and Financial Statement Presentation above for additional information on Cardinal.

The Month of December 2004

The HM Capital Investors purchased Regency Gas Services LLC effective December 1, 2004. As a result of accounting for the acquisition as a purchase and using push-down accounting, we incurred additional depreciation and amortization expense. Depreciation and amortization expense for this one month increased over the preceding monthly amount by $0.6 million or 61% resulting from the step-up in basis of tangible assets as well as the recording of new identifiable intangible assets from the purchase price allocation. The additional interest expense resulted primarily from higher levels of borrowings associated with the acquisition. These levels of borrowings increased to $250.0 million at December 31, 2004 from $66.6 million at December 31, 2003.

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Period from January 1, 2004 to November 30, 2004 vs. Period from Inception (April 2, 2003) to December 31, 2003

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

	Regency LLC Predecessor Period from January 1, 2004 to November 30, 2004	Regency LLC Predecessor Period from Inception (April 2, 2003) to December 31, 2003	$ Change	% Change
		($ in millions)		
Revenues	$ 432.3	$ 186.5	$ 245.8	132%
Cost of sales	362.7	163.4	199.3	122
Total segment margin(a)	69.6	23.1	46.5	201
Operating expenses	17.8	7.0	10.8	154
General and administrative	6.6	2.7	3.9	144
Transaction expenses	7.0	0.7	6.3	900
Depreciation and amortization	10.1	4.3	5.8	135
Operating income	28.1	8.4	19.7	235
Interest expense, net	(5.1)	(2.4)	(2.7)	113
Loss on debt refinancing	(3.0)		(3.0)	n/m
Other income and deductions, net	0.1	0.2	(0.1)	(50)
Net income from continuing operations	20.1	6.2	13.9	224
Discontinued operations	(0.1)		(0.1)	n/m
Net income	$ 20.0	$ 6.2	$ 13.8	223%
System inlet volumes (MMBtu/d)(b)	495,581	423,043	72,538	17%
Processing volumes (MMBtu/d)	237,247	136,127	101,120	74

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

(b) 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 the results of operations.

	Regency LLC Predecessor Period from January 1, 2004 to November 30, 2004	Regency LLC Predecessor Period from Inception (April 2, 2003) to December 31, 2003	$ Change	% Change
	($ in millions)			
Segment Financial and Operating Data:				
Gathering and Processing Segment				
Financial data:				
Segment Margin	$ 61.4	$ 18.9	$ 42.5	225%
Operating expenses	16.2	6.1	10.1	166
Operating data:				
Throughput (thousand MMBtu/d)	303	211	92	44
NGL gross production (Bbls/d)	14,487	9,434	5,053	54
Transportation Segment				
Financial data:				
Segment Margin	$ 8.2	$ 4.2	$ 4.0	95%
Operating expenses	1.6	0.9	0.7	78
Operating data:				
Throughput (thousand MMBtu/d)	192	212	(20)	(9)

Results of operations for the year ended December 31, 2003 comprise the period from inception from April 2, 2003 through December 31, 2003; however, the period included only seven months of active operations which began on June 2, 2003.

Net Income. Net income for the eleven months ended November 30, 2004 increased $13.8 million compared with the seven months of active operations in 2003. Net income was significantly enhanced due to the contribution of $22.1 million of segment margin related to the purchase of the west Texas assets in 2004. Interest expense, net increased $2.7 million primarily due to higher net interest expense related to debt incurred to fund the west Texas assets acquisition. In the eleven months ended November 30, 2004, we wrote off $3.0 million of debt issuance costs in connection with the amendment of our current credit facilities and the repayment of our prior facility. Depreciation and amortization expense increased $5.8 million primarily due to our higher depreciable basis following the purchase of the west Texas assets. General and administrative expense increased $3.9 million primarily as a result of higher employee-related expenses and professional and consulting expenses. Operating expenses increased $10.8 million primarily due to our west Texas facilities operating seven months in 2004 versus none in the 2003 period and the difference of four more months in the comparable periods.

Total Segment Margin. Total segment margin for the eleven months ended November 30, 2004 increased to $69.6 million from $23.1 million for the seven months of active operations in 2003, a 201% increase. Of this increase:

$22.1 million was produced by operating assets acquired in west Texas in March of 2004;

$14.5 million was attributable to the operation of our north Louisiana and mid-continent assets, which were acquired in June 2003, for eleven months in the 2004 period compared with seven months of active operations in

2003 period;

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- $0.7 million resulted from NGL marketing operations, which were present in the eleven months ended November 30, 2004 but absent in the seven months of active operations in 2003; and

- the remaining $9.2 million resulted from increased margins per unit of throughput.

Segment margin for the Gathering and Processing segment increased to $61.4 million for the eleven months ended November 30, 2004 from $18.9 million for the seven months of active operations in 2003, a 225% increase. Of this increase:

- $22.1 million was produced by operating assets acquired in west Texas in March of 2004;

- $12.1 million was attributable to the operation of our north Louisiana and mid-continent gathering and processing assets, which were acquired in June 2003, for eleven months in the 2004 period as compared to seven months of active operations in the 2003 period;

- $0.7 million was attributable to NGL marketing operations; and

- the remaining $7.6 million resulted from increased margins per unit of throughput, primarily as a result of commodity price changes.

Segment margin for the Transportation segment increased to $8.2 million for the eleven months ended November 30, 2004 from $4.2 million for the seven months of active operations in 2003, a 95% increase. Of this increase:

- $2.4 million was attributable to operation of the north Louisiana and mid-continent assets for eleven months in the 2004 period as compared to seven months of active operations in the 2003 period; and

- $1.5 million was attributable to increased margins per unit of throughput, primarily as a result of changes in contract mix in 2004.

Operating Expenses. Operating expenses for the eleven months ended November 30, 2004 increased to $17.8 million from $7.0 million in the seven months ended of active operations in 2003, a 154% increase. The addition of the west Texas assets to our Gathering and Processing segment accounted for $6.5 million of the increase. The remaining increase is attributable to operations for eleven months in the 2004 period as compared to seven months of active operations in the 2003 period, with $3.6 million of the increase resulting from our Gathering and Processing segment and $0.7 million of the increase resulting from our Transportation segment.

General and Administrative Expense. General and administrative expense increased to $6.6 million in 2004 from $2.7 million in 2003, a 144% increase. The increase is primarily attributable to employee related expenses of $2.1 million and professional and consulting expenses of $1.3 million. The employee related expenses and the professional and consulting expenses were impacted by the eleven months of expense in 2004 versus seven months of active operations in 2003 as well as an increase in payroll expense in 2004 associated with our west Texas assets.

Transaction Expense. Regency LLC Predecessor incurred internal non-recurring expenses related to the sale of Regency Gas Services LLC to the HM Capital Investors in the amount of $7.0 million in 2004. These expenses consist of compensation, legal and other expenses and were paid by Regency LLC Predecessor prior to the HM Capital Investors acquisition. In 2003, the Regency LLC Predecessor incurred $0.7 million of legal and other organization expenses related to the formation of Regency LLC Predecessor.

Depreciation and Amortization. Depreciation and amortization increased to $10.1 million in 2004 from $4.3 million in 2003, a 135% increase. In 2004, depreciation expense of $3.0 million was associated with our west Texas assets in the Gathering and Processing segment. The remaining increase in depreciation and amortization expense results from eleven months of expense in 2004 versus seven months of active operations in 2003, primarily in the non-west Texas portion of the Gathering and Processing segment.

Interest Expense, Net. Interest expense increased $2.7 million or 113% in 2004 compared to 2003 primarily due to the increased level of borrowings, which were used to finance acquisitions and provide the necessary working capital for the larger enterprise.

Loss on Debt Refinancing. We expensed approximately $3.0 million of unamortized debt issuance costs upon the March 1, 2004 amendment and the December 1, 2004 repayment of our prior credit facility.

Federal Income Tax. We are a limited liability company. Accordingly, we are not subject to federal income taxes. Our members incur the liability for federal income taxes associated with income produced by our business.

Other Matters

Hurricane Katrina and Hurricane Rita. Hurricanes Katrina and Rita struck the Gulf Coast region of the United States on August 29, 2005 and September 24, 2005, respectively, causing widespread damage to the energy infrastructure in the region. The storms did not cause material direct damage to any of our assets in the region. The storms negatively affected the nation s short term energy supply and natural gas and NGL prices increased significantly thereafter. These higher commodity prices had a favorable net effect on our results of operations as we were, and continue to be, a net seller of these commodities.

While neither Hurricane Katrina nor Hurricane Rita caused material direct damage to our facilities, Hurricane Rita did disrupt the operations of NGL pipelines and fractionators in the Houston, Texas area. As a result of these disruptions, we were forced temporarily to curtail producers in the west Texas region for approximately four days and to operate our north Louisiana processing assets in a reduced recovery mode for approximately six days. We have not experienced ongoing effects from these temporary disruptions.

Environmental. A Phase I environmental study was performed on our west Texas assets by an environmental consultant engaged by us in connection with our pre-acquisition due diligence process in 2004. The study indicated that most of the identified environmental contamination had either been remediated or was being remediated by the previous owners or operators of the properties. We believe that the likelihood that we will be liable for any significant potential remediation liabilities identified in the study is remote. We have an environmental pollution liability insurance policy that covers any undetected or unknown pollution discovered in the future. The policy pays for clean-up costs and damages to third parties and has a ten-year term with a $10 million limit subject to certain deductibles.

In March 2005, the Oklahoma Department of Environmental Quality, or ODEQ, sent a notice of violation, alleging that we operate the Mocane processing plant in Beaver County, Oklahoma in violation of the National Emission Standard for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities, or NESHAP, and the requirements to apply for and obtain a federal operating permit (Title V permit). After seeking and obtaining advice from the Environmental Protection Agency, the ODEQ issued an order requiring us to apply for a Title V permit with respect to emissions from the Mocane processing plant by April 2006. No fine or penalty was imposed by the ODEQ and we intend to comply with the order. Resolution of this matter will not have a material adverse effect on our consolidated results of operations, financial condition, or cash flows.

In November 2004, the Texas Commission on Environmental Quality, or TCEQ, sent a Notice of Enforcement, or NOE, to us relating to the operation of the Waha processing plant in 2001 before it was acquired by us. We settled this NOE with the TCEQ in November 2005.

Absent the alleged physical or operational changes at the Waha processing plant that precipitated the NOE, the air emissions at the plant would have been limited, based on the plant s grandfathered status under the relevant federal statutory standards, only by historical amounts until 2007. In anticipation of the expiration of that status, we submitted to the TCEQ in early February 2005 an application for a state air permit for emissions from the Waha plant predicated on the construction of an acid gas reinjection well and, after completion of the well and facilities, the reinjection of the emitted gases. That permit has been issued and requires completion of construction of the well by the end of February 2007. We estimate the capital expenditure relating to the well at approximately $6.0 million.

Liquidity and Capital Resources

We expect our sources of liquidity to include:

- cash generated from operations;
- borrowings under our credit facilities;
- debt offerings; and
- issuance of additional partnership units.

We believe that the cash generated from these sources will be sufficient to meet our minimum quarterly cash distributions and our requirements for short-term working capital and growth capital expenditures for the next twelve months.

Cash Flows and Capital Expenditures

Since the inception of our operations in June 2003 through December 31, 2005, there have been several key events that have had major impacts on our cash flows. They are:

- the acquisition of the El Paso assets on June 2, 2003 in the amount of approximately $119.5 million which was financed through equity of $53.7 million and debt of $70 million;
- the acquisition of the Waha assets on March 1, 2004 for $67.3 million of cash and $1 million of assumed liabilities. We financed this acquisition with $10 million of new equity with the balance in debt;
- the acquisition of Regency Gas Services LLC by the HM Capital Investors on December 1, 2004 for approximately $414 million, net of working capital adjustments, which was funded primarily through $243 million of term notes and $171 million of equity; and
- construction of our Regency Intrastate Enhancement Project at an estimated cost of $157 million, which began in May 2005 and was financed through cash flows from operations, long-term debt and a $15 million equity contribution.

Working Capital (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. Our working capital was $(5.5) million at December 31, 2003, $1.9 million at December 31, 2004 and $(27.7) million at December 31, 2005.

The net increase in working capital from December 31, 2003 to December 31, 2004 of $7.4 million resulted primarily from the following factors:

- an increase in cash and cash equivalents of $1.7 million;
- a $2.8 million increase in the value of risk management assets, resulting from the purchase of calendar 2005 crude oil put options for $2.0 million that we partially funded with an equity investment, and from a $0.8 million unrealized increase in the value of NGL swap contracts;
- a $9.2 million reduction in the amount of short-term debt partially offset by;
- both accounts receivable and accounts payable increased from 2003 to 2004 due to the addition of the west Texas operations in March 2004 resulting in a net $6.6 million decrease.

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The net decrease in working capital from December 31, 2004 to December 31, 2005 of $29.6 million resulted from three primary factors:

a $18.7 million decrease in the net of accounts receivable and accounts payable. This change is primarily attributable to a $21.4 million increase in accounts payable related to the construction of our Regency Intrastate Enhancement Project. Since June 30, 2005, we have financed the project with long-term debt and a $15 million equity contribution. The decrease is partially offset by the payment in February 2005 of a post-closing adjustment payment to our former owners in the amount of $5.8 million.

a $12.3 million decrease in the value of our current risk management net assets. As a result of increases in NGL prices, the market value of these contracts has resulted in a liability which, if prices remained unchanged, would be paid over the course of the next twelve months.

these amounts were offset in part by a $2.0 million decrease in current portion of long-term debt, due to our second amended credit facility, which no longer requires scheduled principal payments.

We expect to improve our working capital position during the first quarter of 2006 as a result of the completion of the Regency Intrastate Enhancement Project and paying the related construction expenses. We cannot predict the impact of our derivative instruments on working capital. With respect to the net risk management liabilities, our cash flows from the sale of products at their market prices will allow us to satisfy these obligations should they materialize.

Cash Flows from Operations. Our cash flows from operations for the eleven months ended November 30, 2004 increased by $25.9 million or 399% from the seven-month period from our date of commencement of operations (June 2, 2003) through December 31, 2003. For the year ended December 31, 2005, our cash flows from operations increased by $3.5 million or 13% from the combined year ended December 31, 2004.

The increase in the operating cash flows during the eleven-month period ended November 30, 2004 as compared to the seven months ended December 31, 2003 resulted primarily from the increased volumes attributable to the acquisition of our west Texas assets in March 2004. In addition, we commenced active operations in June 2003 and, as a result, 2003 included only seven months of operations while the 2004 period included eleven months of operations. For the eleven months ended November 30, 2004, the west Texas operations contributed the following increases over the seven months ended December 31, 2003: total revenue of $104.6 million, cost of gas and liquids and other cost of sales in the amount of $82.5 million and segment margin of $22.1 million. During the eleven-month period ended November 30, 2004, higher natural gas prices also contributed to improved operating cash flow.

Net cash provided by operating activities increased to $31.0 million for the year ended December 31, 2005 compared with $27.5 million for the combined year ended December 31, 2004. The increase was primarily due to increased throughput volumes from the Transportation Segment and north Louisiana region of the Gathering and Processing Segment. The increased price levels for NGLs increased our cash flows from operations, but these increases were matched by cash outflows from our risk management activities, achieving the cash stabilizations goals of our risk management policy. The increase in cash flows from operations was partially offset by an increase in cash interest paid of $10.4 million, as the amount of our debt financing significantly increased following the HM Capital Transaction and in connection with our Regency Intrastate Enhancement Project.

For further information regarding our risk management portfolio, please read Quantitative and Qualitative Disclosures About Market Risk.

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 operating 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 lines of credit. The maximum amounts of revolving line of credit borrowings outstanding during the eleven months

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ended November 30, 2004 and during the year ended December 31, 2005 were $15.0 million and $50.0 million, respectively.

Cash Flows Used in Investing Activities. Our cash flows used in investing activities for the eleven months ended November 30, 2004 decreased by $38.4 million or approximately 31% over the seven-month period ended December 31, 2003. For the year ended December 31, 2005, our cash flows used in investing activities decreased by $64.5 million compared to the combined year ended December 31, 2004.

Our investing cash flows in 2003 were $123.2 million, consisting of $119.5 million invested in our mid-continent and north Louisiana assets in the acquisition from El Paso Field Services LP and affiliates and $3.6 million in capital expenditures.

Items comprising our investing activities during the eleven-month period ended November 30, 2004 include:

- $67.3 million invested in our west Texas assets acquired from Duke Energy Field Services in March 2004;
- $3.5 million invested in gas processing assets acquired from Cardinal on April 1, 2004;
- $15.1 million invested in capital expenditures partially offset by;
- $1.2 million received in connection with a distribution from an escrow account relating to the El Paso acquisition.

For the one month ended December 31, 2004 cash flows used in investing activities were $129.9 million, consisting of $127.8 million of cash payments in connection with the acquisition of Regency Gas LLC by the HM Capital Investors on December 1, 2004 and $2.1 million invested in capital expenditures.

Our cash flows used in investing activities for the year ended December 31, 2005 were $150.2 million, consisting of:

- $151.5 million invested in capital expenditures relating to our Regency Intrastate Enhancement Project and maintenance capital expenditures;
- $5.8 million invested in acquisition expenses that were paid in February 2005 relating to the acquisition of Regency Gas Services LLC by the HM Capital Investors partially offset by;
- $6.0 million of proceeds from the sale of Cardinal assets; and
- $1.1 million of proceeds from the sale of NGL line pack.

Cash Flows Provided by Financing Activities. Our cash flows provided by financing activities for the eleven months ended November 30, 2004 decreased by $61.9 million or approximately 52% from the seven-month period ended December 31, 2003. For the year ended December 31, 2005, our cash flows provided by financing activities decreased by $69.3 million or approximately 37% as compared to the combined year ended December 31, 2004.

Our cash flows in 2003 were $118.2 million, consisting of $53.8 million of net increases in member equity investments and $70.0 million in proceeds of borrowings under our credit agreement, all of which were used to finance the acquisition of our mid-continent and north Louisiana assets. These amounts were offset by principal repayments of $3.4 million and the payment of debt issuance costs in the amount of $2.0 million.

Our cash flows provided by financing activities during the eleven months ended November 30, 2004 were $56.4 million, consisting of:

- $10.0 million in proceeds from member equity investments to finance our investment in our west Texas assets;

- $45.4 million in proceeds from borrowings under our credit agreement, also to finance our investment in our west Texas assets;
- $10.5 million of repayments under our credit facilities;
- $13.0 million of borrowings under our revolving credit facility to finance our investment in our west Texas assets; and
- payment of $1.5 million for debt issuance costs associated with the establishment of credit facilities.

For the one-month period ended December 31, 2004, our financing cash flows consisted of:

- $250.0 million in proceeds of borrowings under our credit agreement which was established for our acquisition by the HM Capital Investors;
- $114.5 million of repayments of principal under credit agreements terminated as part of the acquisition by the HM Capital Investors;
- payment of $7.5 million for debt issuance costs associated with the establishment of our credit facilities; and
- $4.5 million in proceeds from member equity investments to finance a portion of our purchase of crude oil puts.

In comparison, our net financing cash flows for the year ended December 31, 2005 were $119.6 million, consisting of:

- $60.0 million in proceeds of borrowings under the term loan provisions of our credit facility;
- $15.0 million in equity contributions from the HM Capital Investors;
- $50.0 million in proceeds and repayments of borrowings under our revolving credit facility;
- $3.8 million in debt issuance costs related to amendments to our credit facility;
- $1.6 million in scheduled repayments of borrowings under our term loan credit facility.

Capital Requirements

The midstream energy business can be capital intensive, requiring significant investment for the acquisition or development of new facilities. We categorize our capital expenditures as either:

- Growth capital expenditures, which are made to acquire additional assets to increase our business, to expand and upgrade existing systems and facilities or to construct or acquire similar systems or facilities; or
- Maintenance capital expenditures, which are made to replace partially or fully depreciated assets, to maintain the existing operating capacity of our assets and extend their useful lives or to maintain existing system volumes and related cash flows.

During the year ended December 31, 2005, our growth capital expenditures were $162.3 million and our maintenance capital expenditures were $7.8 million, including non-cash expenditures in accounts payable. The major portion of our growth capital expenditures for 2005 was incurred in connection with our Regency Intrastate Enhancement Project.

Since our inception in 2003, we have made substantial growth capital expenditures, including those relating to the acquisition of our north Louisiana assets and mid-continent assets in 2003, our west Texas assets in 2004, and the construction of the Regency Intrastate Enhancement Project in 2005. We anticipate that we will continue to make significant growth capital expenditures. Consequently, our ability to develop and maintain sources of funds to meet our capital requirements is critical to our ability to meet our growth objectives.

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Our 2006 budget includes $25.1 million of identified organic growth capital expenditures. These expenditures relate to several projects, including a dewpoint control conditioning facility in our north Louisiana region, a gathering system development project in our mid-continent region, an acid gas reinjection well at the Waha gas processing plant and the remaining expenditures on our Regency Intrastate Enhancement Project. We expect that these growth capital expenditures will be funded by borrowings under our credit facility.

We continually review opportunities for both organic growth projects and acquisitions that will enhance our financial performance. Since we will distribute most of our available cash to our unitholders, we will depend on borrowings under our credit facility and the incurrence of debt and equity securities to finance any future growth capital expenditures or acquisitions.

In January 2005, we initiated the planning, design, implementation and construction of our Regency Intrastate Enhancement Project. In July 2005, we amended and restated our credit facilities, increasing the available term loans to $309.0 million from $249.0 million, increasing the available revolving credit to $150.0 million from $40.0 million and increasing the available credit for the issuance of letters of credit (which reduces available revolving credit) to $30.0 million from $20.0 million. We also negotiated for, and received, an increase in the capital spending covenant that allowed us to construct the project. The term loans originally consisted of $260.0 million of first lien debt and $50.0 million of second lien debt.

Prior to consummation of the additional financing, we repaid the $10.0 million in outstanding revolving credit loans and at the consummation we borrowed an additional $25.0 million in term loans, increasing the outstanding borrowings under our credit facilities to $274.0 million. We subsequently borrowed $35.0 million on September 26, 2005 to meet capital expenditure requirements associated with the Regency Intrastate Enhancement Project.

On November 30, 2005, we amended our credit facilities further to consolidate our secured indebtedness under a single credit facility and to permit the reorganization and operation of our company as a publicly traded limited partnership.

Second Amended and Restated Credit Agreement

On November 30, 2005, Regency Gas Services LLC, or RGS, our wholly owned subsidiary and operating partnership, amended and restated its $410.0 million first lien credit agreement in order to increase the facility to $470.0 million and to increase the availability for letters of credit to $50.0 million. In addition, RGS has the option to increase the term loan commitments under the facility on up to four separate occasions, provided that each such increase must be at least $5.0 million, all such increases must not exceed $40.0 million in the aggregate, no default or event of default shall have occurred or would result due to such increase, and all other additional conditions for the increase of term loan commitments set forth in the facility have been met.

As of December 31, 2005, the facility consisted of $258.4 million of outstanding term loans, $50.0 million of term loan commitments and $160.0 million of revolving loan commitments. RGS obligations under the facility are secured by substantially all of our assets. The revolving loans under the facility will mature on December 1, 2009, and the term loans thereunder will mature on June 1, 2010.

Interest on borrowings under the second amended and restated credit facility will be calculated, at the option of RGS, at either (a) a base rate plus an applicable margin of 1.25% per annum or (b) an adjusted LIBOR rate plus an applicable margin of 2.25% per annum. RGS shall pay (i) a commitment fee equal to 0.50% per annum of the unused portion of the revolving loan commitments, (ii) a participation fee for each revolving lender participating in letters of credit equal to 2.25% per annum of the average daily amount of such lender s letter of credit exposure, and (iii) a fronting fee to the issuing bank of letters of credit equal to 0.125% per annum of the average daily amount of the letter of credit exposure.

In addition, RGS amended and restated its $50.0 million second lien credit agreement on November 30, 2005; however, such second lien credit facility was repaid in full through a draw down of the $50.0 million of term loan commitments under the facility described above and terminated on December 2, 2005.

Third Amended and Restated Credit Agreement

Upon the consummation of our initial public offering, the second amended and restated credit facility was amended and restated automatically, and the third amended and restated credit facility became effective. The revolving loan commitments, the ability to increase its term loan commitments, and the maturity dates under the third amended and restated credit facility are the same as they were under the second amended and restated credit facility and RGS obligations are secured by substantially all of our assets.

The Third Amended and Restated Credit Facility contains financial covenants requiring us to maintain total leverage and interest coverage ratios within certain thresholds.

The Third Amended and Restated Credit Facility restricts RGS ability to pay dividends, but it authorizes RGS to reimburse us for expenses, and to pay dividends to us, pursuant to our Amended and Restated Agreement of Limited Partnership (so long as no default or event of default has occurred or is continuing). The Third Amended and Restated Credit Facility also contains various covenants that limit (subject to certain exceptions and negotiated baskets), among other things, RGS ability (but not our ability) to:

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

At December 31, 2005, RGS had outstanding letters of credit totaling $10.7 million related to our risk management activities. The total fees for letters of credit accrue at an annual rate of 2.38%, which is applied to the daily amount of letters of credit exposure. As of March 22, 2006, we had $0.3 million outstanding letters of credit related to our risk management activities.

Off-Balance Sheet Transactions and Guarantees. We have no off-balance sheet transactions or obligations.

Credit Ratings and Debt Covenants. The current credit ratings on our debt under our credit facility are B1 with a negative outlook by Moody s Investor Service and B+ with a stable outlook by Standard and Poor s. At December 31, 2005, we were in compliance with the covenants of the credit facilities. See Note 3 to the accompanying financial statements for additional information on the credit facilities.

Total Contractual Cash Obligations. The following table summarizes our total contractual cash obligations as of December 31, 2005. The $308.4 million of term loans outstanding on December 31, 2005 is scheduled for interest rate resets on three-month intervals.

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Interest rates were reset on December 31, 2005.

	Payments Due by Period				
Contractual Obligations	**Total**	**2006**	**2007-2008**	**2009-2010**	**Thereafter**
Long-term Debt (including interest)(1)	$ 483.5	$ 24.6	$ 51.5	$ 407.4	$ -
Operating Leases	1.5	0.5	0.9	0.1	-
Purchase Obligations(2)(3)(4)	3.8	3.8	-	-	-
Total Contractual Obligations	$ 488.8	$ 28.9	$ 52.4	$ 407.5	$ -

(1) Assumes a current LIBOR interest rate of 4.53% plus the applicable margin, which remains constant in all periods. The contractual obligations also include the effect of interest rate hedges on a notional amount of $200 million through March 2009.

(2) Represents the purchase obligation for a pipeline project in north Louisiana.

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

(4) These amounts do not include an estimated $4.5 million and $1.5 million that we expect to spend in 2006 and 2007, respectively, for the construction of an acid gas reinjection well at our Waha gas processing plant.

The table above does not include our existing obligations as of December 31, 2005 under our ten year financial advisory and monitoring and oversight agreements between us and an affiliate of HM Capital to pay certain management fees and transaction advisory fees to the affiliate of HM Capital. We paid $9.0 million of the proceeds from our initial public offering to the affiliate of HM Capital to terminate these agreements. As a result, we do not have any continuing obligation to make payments under these agreements.

Recent Accounting Pronouncements

On October 6, 2005, the Financial Accounting Standards Board (the FASB) issued Staff Position FAS 13-1 concerning the accounting for rental expenses associated with operating leases for land or buildings that are incurred during a construction period. We have considered how this might apply to our payment for rights-of-way associated with the construction of pipelines, and we do not anticipate any changes to our accounting practices or impacts on our results of operations or financial condition in light of the recently issued Staff Position FAS 13-1.

In May 2005, the FASB issued Statement of Financial Accounting Standard (SFAS) No. 154, Accounting Changes and Error Corrections a replacement of APB Opinion No. 20 and FASB Statement No. 3. This accounting standard is effective for fiscal years beginning after December 15, 2005. We do not believe this accounting standard will have a material adverse effect on our results of operations, financial condition or cash flows.

We account for our asset retirement obligations in accordance with Statement of Financial Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations and FIN 47 Accounting for Conditional Asset Retirement Obligations. These accounting standards require us to recognize on the balance sheet the net present value of any legally binding obligation to remove or remediate the physical assets that we retire from service, as well as any similar obligations for which the timing and/or method of settlement are conditional on a future event that may or may not be within our control. While we are obligated under contractual agreements to remove certain facilities upon their retirement, we are unable to reasonably determine the fair value of any asset retirement obligations as of December 31, 2005 and 2004 because the settlement dates, or ranges thereof, were indeterminable and could range up to ninety-six years, and the undiscounted amounts are immaterial. An asset retirement obligation will be recorded in the periods wherein we can reasonably determine the settlement dates.

In December 2004, the FASB issued SFAS No. 123 (revised 2004), Share-based Payment, which is a revision of SFAS No. 123, Accounting for Stock-Based Compensation. This statement establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. SFAS No. 123 (revised 2004) is effective for the first interim or annual reporting period that begins after June 15, 2005. We adopted SFAS 123(R) Share-Based Payment in the first quarter of 2006 which had no impact to us as no LTIP awards were outstanding during 2005.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES 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 Managing GP is responsible for delegation of transaction authority levels, and the Risk Management Committee of our general partner is responsible for the overall approval of market risk management policies. The Risk Management Committee is composed of directors (including, on an ex officio basis, our chief executive officer) who receive regular briefings on positions and exposures, credit exposures and overall risk management in the context of market activities. The Risk Management Committee is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits.

See Critical Accounting Policies and Estimates Risk Management Activities for further discussion of the accounting for derivative contracts.

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 may be exposed to commodity price risk. For example, under many of our contracts in place in west Texas, we are obligated to purchase gas at a price derived from published first of the month, or FOM, index prices. We then sell the gas at the same index price. In November 2005, in a highly unusual circumstance, there were very few baseload FOM index sales reported and we were unable to find buyers at these prices. The ensuing daily cash price was substantially less than the posted FOM index. We were able to convince most of the producers of this natural gas that the index price was an anomaly and that the purchase price and the sale price should be matched. In order to prevent this from occurring again, we are in the process of amending these contracts to provide for a closer matching of the pricing of purchases and sales in these circumstances.

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. Historically, changes in the prices of heavy NGLs, such as natural gasoline, have generally correlated with changes in the price of crude oil. For a discussion of the volatility of natural gas and NGL prices, please read Risk Factors. 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

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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. Our overall expected direct exposure to movements in natural gas prices is minimal as a result of natural hedges inherent in our contract portfolio. Natural gas prices, however, can also affect our profitability indirectly by influencing the level of drilling activity and related opportunities for our service. We are a net seller of NGLs, and as such our financial results are exposed to fluctuations in NGLs pricing. We have executed swap contracts settled against ethane, propane, butane and natural gasoline market prices, supplemented with crude oil put options. As a result, we have hedged approximately 95% of our expected exposure to NGL prices in 2006, approximately 75% in 2007 and approximately 50% in 2008. We continually monitor our hedging and contract portfolio and expect to continue to adjust our hedge position as conditions warrant.

The following table sets forth certain information regarding our NGL swaps outstanding at December 31, 2005:

Period	Commodity	Notional Volume (MBbls)	We Pay	We Receive ($/gallon)	Fair Value (Thousands)
Jan. 2006 - Dec 2007	Ethane	929	Index	$ 0.55 to $0.58	$ (4,529)
Jan. 2006 - Dec 2007	Propane	811	Index	$ 0.66 to $0.825	(7,937)
Jan. 2006 - Dec 2007	Butane	427	Index	$ 1.02 to $1.085	(3,076)
Jan. 2006 - Dec 2007	Natural Gasoline	164	Index	$ 1.22 to $1.26	(665)
Total Fair Value					$ (16,207)

The following table sets forth certain information regarding our crude oil puts:

Period	Commodity	Notional Volume (MBbls)	Strike Prices ($/Bbl)	Fair Value (Thousands)
Jan. 2006 - Dec 2007	NYMEX West Texas Intermediate Crude	2,438	$ 30.00 to $36.50	$ 575

The table below summarizes the changes in commodity and interest rate risk management assets and liabilities for the year ended December 31, 2005.

	$ in millions
Net Risk Management Asset at December 31, 2004	$ 9.0
Settlements of positions included in beginning balance	2.7
Unrealized mark-to-market valuations of positions held at June 30, 2005	(15.3)
Other*	(0.7)
Balance of Risk Management Assets (Liability) at June 30, 2005	(4.3)
Settlements of positions included in June 30, 2005 balance	2.7

Unrealized mark-to-market valuations of positions held at December 31, 2005		0.6
Effective portion of hedges included within Other Comprehensive Income		(11.0)
Other*		(1.2)
Balance of Net Risk Management Liability at December 31, 2005	$	(13.2)

* The amounts reported as other represents the expiration of options for which premiums were paid in prior periods.

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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 parental guarantees.

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 $3.2 million per year. The contract expires in mid-2012 and was secured by a $10.0 million letter of credit. In December 2005, in connection with other contract negotiations, the letter of credit was reduced to $3.3 million and we accepted a Parental Guarantee in the amount of $6.7 million. The customer has 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. At the date of this Annual Report on Form 10-K, the customer was current in its payment obligations.

Interest Rate Risk

The credit markets recently have experienced 50-year record lows in interest rates. As the overall economy strengthens, it is likely that monetary policy will tighten further, resulting in higher interest rates to counter possible inflation. Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly.

We are exposed to variable interest rate risk as a result of borrowings under our existing credit agreement. To minimize this risk, we entered into an interest rate swap in January 2005 for a notional $125 million of the initial $250 million of term loans which effectively fixed our interest rate at 6.47% on this notional amount for a period of two years. When we amended and restated our credit facility in July 2005, we entered into two additional interest rate swaps. The first had a notional amount of $75.0 million, bringing the total notional amount to $200 million with a March 2007 maturity. As a result, we converted $200 million of $309 million of term loans, or approximately two-thirds, of our variable interest rate debt to fixed interest rate debt through March 2007 at a fixed rate of 6.70%. The second interest rate swap had a notional amount of $200.0 million that is effective from April 2007 through March 2009, and effectively fixed our interest rate at 7.36% on this amount for two years. Our variable interest rate debt bears interest at variable rates based on LIBOR or the bank s prime rate. The fair value of our interest rate swaps as of December 31, 2005 was $2.5 million.

On November 30, 2005, we amended and restated our credit agreement. This amendment reduced the applicable margin on our first lien debt by 0.5%, reducing our effective fixed interest rate to 6.20% through March 2007 and 6.86% from April 2007 through March 2009 on a notional amount of $200 million.

ITEM 8. Financial Statements and Supplementary Data.

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

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

None.

ITEM 9A. 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 Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. 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 Managing GP, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rule 13a-15(e) and 15d-15(e) of the Exchange Act). Based on that evaluation, management, including the Chief Executive Officer and Chief Financial Officer of our Managing GP, concluded that our disclosure controls and procedures were effective as of December 31, 2005 to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Exchange Act are recorded, processed, summarized and reported, within the time periods specified in the SEC s rules and forms.

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 disclosure control issues within the Partnership have been detected. These inherent limitations include the realties 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 and the Chief Executive Officer and the Chief Financial Officer of our Managing GP have concluded, as of December 31, 2005, that our disclosure controls and procedures are effective in achieving that level of reasonable assurance.

Management has acknowledged that it is responsible for establishing and maintaining a system of disclosure controls and procedures for the Partnership. We have designed those disclosure controls and procedures to ensure that material information relating to the Partnership, including its consolidated subsidiaries, is made known to management by others within those entities. We have evaluated the effectiveness of our disclosure controls and procedures, as of the end of fiscal year 2005, and concluded that they are effective.

The Partnership is not yet subject to Section 404 of the Sarbanes-Oxley Act which, when applicable, will require the Partnership to include Management s Annual Report on Internal Control Over Financial Reporting and an Attestation Report of Independent Registered Public Accounting Firms in its Annual Report on Form 10-K. Under the applicable rules of the Securities and Exchange Commission, or SEC, Section 404 will not apply to the Partnership until the due date of our annual report for the year ending December 31, 2007.

In anticipation of becoming subject to the provisions of Section 404 of the Sarbanes-Oxley Act of 2002, we initiated in early 2005 a program of documentation, implementation and testing of internal control over financial reporting. This program will continue through this year and next, culminating with our initial Section 404 certification and attestation in early 2008. While our independent registered public accounting firm has not attested to or reported on our internal control over financial reporting as of the end of fiscal 2005, we have evaluated the effectiveness of our system of internal control over financial reporting, as well as changes therein, in compliance with Rule 13a-15 of the SEC s rules under the Securities Exchange Act and have filed the certifications with this annual report required by Rule 13a-14.

In the course of that evaluation, we found no fraud, whether or not material, that involved management or other employees who have a significant role in our internal control over financial reporting and, except to the extent set forth below, no material weaknesses. To the extent that we discovered any matter in the design or operation of our system of internal control over financial reporting that might be considered to be a significant deficiency or a material weakness, whether or not considered reasonably likely to adversely affect our ability to record, process, summarize and report financial information, we reported that matter to our independent registered public accounting firm and to the audit committee of our board of directors.

In the course of preparation of our financial statements for the year ended December 31, 2005, an accounting error was discovered relating to the reclassification of losses from other comprehensive income to earnings which could have understated net income (loss) and overstated other comprehensive income (loss) during the year ended 2005.

The financial statements included herein reflect the correct reclassification of net losses from other comprehensive income and no prior periods were materially misstated. However, the error may have been the result of a material weakness in our internal controls over financial reporting. As a result, management has instituted a change in our internal control over financial reporting designed to avoid any repetition of the error. That change in our internal control over financial reporting was a requirement to conduct a thorough reconciliation of the components of other comprehensive income (loss) on a monthly basis. It is reasonably likely that this change will materially affect our internal control over financial reporting.

ITEM 9B. Other Information.

None.

Part III

ITEM 10. Directors and Executive Officers of the Registrant.

Partnership Management

Regency GP (the General Partner) is our General Partner. The General Partner manages and directs all of our activities. The activities of the General Partner are managed and directed by its general partner, Regency GP LLC (the Managing GP). Our officers and directors are officers and directors of the Managing GP. The owners of the Managing GP may appoint up to ten persons to serve on the Board of Directors of the Managing GP. Although there is no requirement that he do so, the President and Chief Executive Officer of the Managing GP is currently a director of the Managing GP and serves as Chairman of the Board of Directors.

Commencing in December 2005 prior to the initial public offering of the Partnership, our Board of Directors was comprised of its Chairman (the President and Chief Executive Officer of the Managing GP), three persons who qualify as independent under the NASD s standards for audit committee members, and six persons who were either appointed by the sole member of the Managing GP or elected by the other members of the Board of Directors.

Corporate Governance

The Board 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 Managing GP. The Corporate Governance Guidelines, the Code of Business Conduct and the charters of our audit, compensation, nominating and executive committees are available on our website at *www.regencyenergy.com* and in print to any Unitholder who requests any of them. 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 addresses or at our website in general is intended or deemed to be incorporated by reference herein.

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Conflicts Committee

The Board of Directors appoints 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 Managing GP is fair and reasonable to the Partnership and its Common Unitholders. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to the Partnership, approved by all partners of the Partnership and not a breach by the General Partner, the Managing GP or its Board of Directors of any duties they may owe the Partnership or the Common Unitholders. The members of the Conflicts Committee are A. Dean Fuller (Chairman), Robert W. Shower and J. Otis Winters. The Conflicts Committee has not yet held a meeting.

Audit Committee

The Board of Directors has established an Audit Committee in accordance with Section 3(a)(58)(A) of the Exchange Act. The Board of Directors has appointed five directors as members of the Audit Committee, including three individuals who are independent under the NASD s standards for audit committee members to serve on its Audit Committee. In addition, the Board has determined that at least one member of the Audit Committee (Robert W. Shower) 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. A description of the qualifications of Mr. Shower may be found in this Item 10 under Directors and Executive Officers of the General Partner.

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, review our procedures for internal auditing and the adequacy of our internal accounting controls, consider the qualifications and independence of our independent accountants, 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 which may be recommended or required by the independent accountants, and to engage the services of any other advisors and accountants as the Audit Committee deems advisable. The Audit Committee reviews and discusses the audited financial statements with management, discusses with our independent auditors matters required to be discussed by SAS 61 (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. The Board of Directors adopts the Charter for the Audit Committee. Since December 2005, the Audit Committee has been composed of Robert W. Shower (Chairman), A. Dean Fuller and J. Otis Winters, all of whom have been determined by the Board of Directors to be independent within the requirements of the applicable NASD rules, and J. Edward Herring and Robert D. Kincaid.

Compensation and Nominating Committees

Although we are not required under NASD rules to appoint a Compensation Committee or a Nominating/ Corporate Governance Committee because we are a limited partnership, the Board of Directors of the Managing GP 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, as well as any other equity compensation plans adopted by our Common Unitholders. The Compensation Committee is composed of Jason H. Downie (Chairman), Joe Colonnetta and J. Otis Winters, none of whom is an officer or employee of the Managing GP or the Partnership.

The Board of Directors has also appointed a Nominating Committee to assist the Board and the member of our Managing GP (the Member) 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. The Nominating Committee is composed of Joe Colonnetta (Chairman), Jason H. Downie, J. Edward Herring and Robert W. Shower. Matters relating to the election of Directors or to Corporate Governance are addressed to and determined by the full Board of Directors.

Code of Business Conduct

The Board of Directors has adopted a Code of Business Conduct applicable to 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 Managing GP. The Code of Business Conduct is available on our website at www.regencygas.com and in print to any Unitholder who requests it. 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 addresses or at our website in general is intended or deemed to be incorporated by reference herein.

Meetings of Non-management Directors and Communications with Directors

Our non-management directors (as defined by the NASD rules) are required to meet in executive session at each regularly scheduled Board meeting. The position of the presiding director at these meetings is required to be rotated among the independent directors. J. Otis Winters is the presiding director for the meetings of the non-management directors to be held prior to the 2007 Annual Meeting of the Board. Interested parties may make their concerns known to the non-management directors directly and anonymously by writing to the Chairman of the Audit Committee, Regency GP LLC, 1700 Pacific Avenue, Suite 2900, Dallas, Texas 75201.

If the group of the non-management directors includes directors who have not been determined by the Nominating Committee to be independent directors, then, in addition to the meetings of the non-management directors, the independent directors are required to meet in executive session at least once a year. The presiding director shall be chosen by the group of independent directors to preside over and to be responsible for preparing an agenda for the meetings of the independent directors if such meetings are necessary.

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Directors and Executive Officers

The following table shows information regarding the current directors and executive officers of Regency GP LLC. Directors are elected for one-year terms.

Name	Age	Position with Regency GP LLC
James W. Hunt(1)(4)(5)	62	Chairman of the Board, President and Chief Executive Officer
Michael L. Williams	46	Executive Vice President and Chief Operating Officer
Stephen L. Arata	40	Executive Vice President and Chief Financial Officer
William E. Joor III	66	Executive Vice President, Chief Legal and Administrative Officer and Secretary
Charles M. Davis, Jr.(7)	44	Senior Vice-President-Corporate Development
Durell J. Johnson	43	Vice President, Operations and Engineering
Lawrence B. Connors	55	Vice President, Finance and Chief Accounting Officer
Alvin Suggs	53	Vice President and General Counsel
Joe Colonnetta(1)(4)(6)	44	Director
Jason H. Downie(1)(4)(5)(6)	35	Director
A. Dean Fuller(2)(3)	58	Director
Jack D. Furst	47	Director
J. Edward Herring(2)(6)	35	Director
Robert D. Kincaid(2)	45	Director
Gary W. Luce(5)	45	Director
Robert W. Shower(2)(3)(6)	68	Director
J. Otis Winters(2)(3)(4)	73	Director

(1) Member of the Executive Committee. Mr. Colonnetta is chairman of this committee.
(2) Member of the Audit Committee. Mr. Shower is chairman of this committee.
(3) Member of Conflicts Committee. Mr. Fuller is chairman of this committee.
(4) Member of Compensation Committee. Mr. Downie is chairman of this committee. Mr. Hunt is an ex-officio member.
(5) Member of Risk Management Committee. Mr. Luce is chairman of this committee. Mr. Hunt is an ex-officio member.
(6) Member of Nominating Committee. Mr. Colonnetta is chairman of this committee.
(7) Mr. Davis was elected an officer on March 21, 2006 and commenced employment in March 2006.

James W. Hunt was elected Chairman of the Board of Directors of Regency GP LLC and Regency Gas Services in November 2005. Mr. Hunt has served as President and Chief Executive Officer of Regency GP LLC from September 2005 to present. Mr. Hunt has, since his election effective December 1, 2004, served as President, Chief Executive Officer and Director of Regency Gas Services LLC. From 1978 until January 1981, Mr. Hunt served as President and Chief Executive Officer of Diamond M Company, a major offshore drilling company and the predecessor of Diamond Offshore Company. From 1981 through 1987, he served as Chairman and Chief Executive Officer of Cenergy Corporation, a NYSE listed oil and gas exploration, production and pipeline company. During the period from 1987 to 1989, Mr. Hunt was an independent financial consultant. From 1989 until December 2004, Mr. Hunt was engaged in energy investment banking, three years as head of the Houston office of Lehman Brothers Incorporated and most recently as head of the U.S. Energy Group of UBS Securities LLC. Mr. Hunt is an attorney and member of the State Bar of Texas.

Michael L. Williams, P.E., was elected Executive Vice President and Chief Operating Officer of Regency GP LLC in September 2005. From December 2004 to the present, Mr. Williams served as Executive Vice President and Chief Operating Officer of Regency Gas Services LLC. Mr. Williams served as Vice President of Engineering and Operations from October 2002 through September 2004 heading up operations and engineering at Energy Transfer Partners, L.P. Mr. Williams also served as Vice President of Engineering and Operations for Aquila Inc. from 2000 through September 2002 where he was responsible for the Operation and Engineering of Aquila s gas gathering, processing, fractionation, and storage assets.

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 LLC. 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. Prior to UBS, Mr. Arata worked for Deloitte Consulting, focusing on the energy sector.

William E. Joor III was elected Executive Vice President, Chief Legal and Administrative Officer and Secretary of Regency GP LLC in September 2005. Mr. Joor has, since his election effective January 1, 2005, served as Executive Vice President, Chief Legal and Administrative Officer and Secretary of Regency Gas Services LLC. From May 1966 through December 1973, Mr. Joor was associated with, and from then until December 31, 2004 was a partner of, Vinson & Elkins LLP. Mr. Joor s area of specialization was the law of corporate finance and mergers and acquisitions with particular emphasis in the energy sector.

Charles M. Davis, Jr. was elected Senior Vice President Corporate Development for Regency Energy Partners in March 2006. From September 2004 to February 2005, Mr. Davis was Managing Director and Head of Mergers and Acquisitions for Challenger Capital Group Ltd. From July 2002 until September 2004, Mr. Davis was a Managing Director in the Energy and Power Group of UBS Investment Bank. From March 1992 until August 2002, Mr. Davis was a Managing Director in the Global Energy and Power Group of Merrill Lynch. Prior to Merrill, Mr. Davis worked in the Energy Groups of The First Boston Corporation and McKinsey & Co. Mr. Davis has over 20 years experience with Mergers and Acquisitions as well as financing in the pipeline industry.

Durell J. Johnson, P.E., was elected Vice President of Operations and Engineering of Regency GP LLC in September 2005. From December 2004 to the present, Mr. Johnson served as Vice President of Operations and Engineering of Regency Gas Services LLC. Mr. Johnson was Director of Engineering for Energy Transfer Partners, L.P. from October 2003 through October 2004 providing engineering support for all of Energy Transfer s midstream operations. Mr. Johnson was Vice President of engineering for Garrison LTD. from October 2002 until October 2003 where he was responsible for drilling and facilities operations. Mr. Johnson was Manager of Engineering and Construction at Aquila Inc. from 1999 until October 2002. Mr. Johnson has 20 years of diversified experience in the natural gas industry.

Lawrence B. Connors was elected Vice President of Finance and Chief Accounting Officer of Regency GP LLC in September 2005. From December 2004 to the present, Mr. Connors served as Vice President, Finance 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. From August 2000 through November 2001, Mr. Connors was an independent accounting and financial consultant. From 2001 through May 2003 Mr. Connors was a Registered Representative with Foster Financial Group. From 1996 through July 2000, Mr. Connors was the Controller and Chief Accounting Officer of Central and South West Corporation, or CSW; he had managerial responsibilities at three CSW operating companies and CSW Services. Prior to his employment at CSW, he was with Arthur Andersen working with energy and health care audit clients. Mr. Connors is a Certified Public Accountant.

Alvin Suggs was elected Vice President and General Counsel of Regency GP LLC in September 2005. From June 2005 to the present, Mr. Suggs served as Vice President and General Counsel of Regency Gas Services LLC. From June 2003 to June 2005, Mr. Suggs engaged in the private practice of law representing clients in the energy sector, first as a sole practitioner and, after June 2004, with

Thompson & Knight, LLP. Mr. Suggs served as Vice President and Associate General Counsel with El Paso Energy Corporation and General Counsel of El Paso Field Services, L.P. from September 1999 through June 2003. Mr. Suggs served as Senior Counsel to El Paso Field Services, L.P. and El Paso Energy Marketing, L.P. from September 1997 to September 1999, and from 1987 to 1999 he served Texas Oil & Gas Corp., American Oil and Gas Corporation and KN Energy, Inc. in various capacities from Counsel to Assistant General Counsel. Prior to that service, Mr. Suggs was in private practice of law for five years, and also served as Assistant District Attorney for the Fifth Circuit Court District in Mississippi in 1978.

Joe Colonnetta was elected to the Board of Directors of Regency GP LLC in September 2005 and served as Chairman of the Board of Directors until November 2005. From December 2004 to the present, Mr. Colonnetta has served as a director of Regency Gas Services LLC, including service as Chairman of the Board until November 2005. Mr. Colonnetta is a partner at HM Capital. Mr. Colonnetta joined HM Capital in 1998. Prior to joining HM Capital, Mr. Colonnetta was a partner with Metropoulos and Co., an affiliate of HM Capital. Mr. Colonnetta is also Chairman of the Board of Directors of TexStar Field Services and BlackBrush Oil & Gas, and he serves on the Board of Directors of Swift & Company.

Jason H. Downie was elected to the Board of Directors of Regency GP LLC in September 2005. From December 2004 to the present, Mr. Downie has served as a director of Regency Gas Services LLC. Mr. Downie is a partner of HM Capital and has been with the firm since September 2000. From June 1999 to August 2000, Mr. Downie was an associate at Rice Sangalis Toole & Wilson, a mezzanine private equity firm based in Houston, Texas, and from June 1992 through June 1997, Mr. Downie served in various capacities with Donaldson, Lufkin & Jenrette in New York, lastly as an Associate Position Trader in their Capital Markets Group. From June 1997 to June 1999, Mr. Downie attended the McCombs School of Business at the University of Texas. Mr. Downie also serves on the Board of Directors of TexStar Field Services, BlackBrush Oil & Gas and Activant Solutions Holdings Inc.

A. Dean Fuller was elected to the Board of Directors of Regency GP LLC on November 14, 2005. Having sold in 1993 a company he co-founded, Mr. Fuller become President and Chief Executive Officer of Transok, Inc., the natural gas pipeline subsidiary of Central and South West Corporation, until its sale in 1996. Mr. Fuller continued to manage the fuels and gas marketing function of CSW until late 2000 at which time he became Senior Vice President of the midstream business of Aquila, Inc. At the time of the acquisition of Aquila s midstream business by Energy Transfer, Mr. Fuller continued to manage those assets as Senior Vice President, and served as President of Oasis Pipeline Company after its acquisition by Energy Transfer. Mr. Fuller resigned his positions with Energy Transfer in August 2004.

Jack D. Furst was elected to the Board of Directors of Regency GP LLC on December 8, 2005. Mr. Furst is a partner with HM Capital and has been with the firm since its formation in 1989. From 1987 to 1989, Mr. Furst served as a vice president and subsequently a partner of Hicks & Haas. From 1984 to 1986, Mr. Furst was a merger & acquisitions/corporate finance specialist for The First Boston Corporation in New York. Before joining First Boston, Mr. Furst was a financial consultant at Price Waterhouse. Mr. Furst received his MBA from the Graduate School of Business at the University of Texas. Mr. Furst also serves on the Board of Directors of Activant Solutions Holdings Inc. and various other privately held companies.

J. Edward Herring was elected to the Board of Directors of Regency GP LLC in September 2005. From December 2004 to the present, Mr. Herring has served as a director of Regency Gas Services LLC. Mr. Herring is a partner at HM Capital and has been with the firm since 1998. From 1996 to 1998, Mr. Herring attended Harvard Business School. From 1993 to 1996, Mr. Herring was an investment banker with Goldman, Sachs & Co. Mr. Herring also serves on the Board of Directors of Swift & Company, BlackBrush Oil & Gas, TexStar Field Services and Swett & Crawford.

Robert D. Kincaid was elected to the Board of Directors of Regency GP LLC in September 2005. From January 2005 to the present, Mr. Kincaid has served as a director of Regency Gas Services LLC. Mr. Kincaid is a co-founder, with Mr. Luce, and Managing Director of K-L Energy Partners, LLC, a private equity management firm formed in April 2004 to focus on investments in the midstream and

downstream energy and power sectors. From October 1998 until December 2003, Mr. Kincaid was a principal of Haddington Ventures, LLC, another private equity management firm focused on energy-related investing. From December 2003 until March 2004, Mr. Kincaid served as a consultant to Haddington Ventures. Mr. Kincaid served as Treasurer of TPC Corporation, a firm engaged in the natural gas marketing, pipeline and storage sectors, from 1992 until its sale to PacifiCorp in April 1997. Mr. Kincaid began his career in investment banking and mezzanine fund management in Houston, Texas.

Gary W. Luce was elected to the Board of Directors of Regency GP LLC in September 2005. From January 2005 to the present, Mr. Luce has served as a director of Regency Gas Services LLC. Mr. Luce is a co-founder, with Mr. Kincaid, and has been Managing Director of K-L Energy Partners, LLC since its inception in April 2004. During the period from November 2002 until April 2004, Mr. Luce, in order to comply with the non-competition provisions of his employment agreement with Reliant Resources, Inc., acted as an independent financial consultant. Mr. Luce served as a member of the senior management team for two public energy-related companies, EOTT Energy Partners, LP from April 1994 to December 1998 and Reliant Resources, Inc. from October 1999 to November 2002. Mr. Luce also served in various capacities with McKinsey & Company, Inc., the international management-consulting firm, most recently as a downstream energy practice principal.

Robert W. Shower was elected to the Board of Directors of Regency GP LLC on November 14, 2005. During the period from 1964 through 1986, Mr. Shower was employed by The Williams Companies, ultimately serving as Executive Vice President, Finance and Administration, Chief Financial Officer and a director. Since then, Mr. Shower has served as a managing director of Shearson Lehman Hutton Incorporated from 1986 to 1990, Vice President and Chief Financial Officer of AmeriServe from 1990 to 1991, Senior Vice President, Corporate Development for Albert Fisher, Inc. from 1991 to 1992 and Executive Vice President, Chief Financial Officer and a director of Seagull Energy Corporation from 1992 to 1996. Currently, Mr. Shower is a member of the board of directors and chairman of the audit committee of Edge Petroleum Corporation. Mr. Shower was formerly a member of the board of directors and chairman of the audit committee of Lear Corporation, Highlands Insurance Group, Inc. and Nuevo Energy Company.

J. Otis Winters was elected to the Board of Directors of Regency GP LLC on November 14, 2005. The following are exemplary of Mr. Winters extensive business experience: Vice President of Warren American Oil Company from 1964 to 1965; President and a director of Educational Development Corporation from 1966 to 1973; Executive Vice President and a director of The Williams Companies, Inc. from 1973 to 1977; Executive Vice President and a director of First National Bank of Tulsa from 1978 to 1979; President and a director of Avanti Energy Corporation from 1980 to 1987; Managing Director of Mason Best Company from 1988 to 1989; Chairman, director and co-founder of The PWS Group from 1990 to 2000 and from 2001 to date Chairman and Chief Executive Officer of Oriole Oil Company. Mr. Winters has served on the board of directors of 20 publicly owned corporations, including Alton Box Board Company, AMFM, Inc., AMX Corporation, Dynegy, Inc., Liberty Bancorp., Inc., Tidel Engineering, Inc., Trident NGL, Inc. and Walden Residential Properties, Inc.

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 and its affiliates will, however, be reimbursed for all expenses incurred on our behalf. These expenses include the cost of employee, officer and director compensation 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 and its affiliates may be reimbursed.

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ITEM 11. Executive Compensation.

We, our general partner and Regency GP LLC were formed in September 2005. Because our general partner is a limited partnership, its general partner, Regency GP LLC, will manage our operations and activities through its board of directors and executive officers. All of our officers and employees are employed by Regency GP LLC. Because they are employees of Regency GP LLC, the compensation of the executive officers of Regency GP LLC (other than any awards under the benefit plans described below) will be set and paid by Regency GP LLC. Officers and employees of Regency GP LLC may participate in employee benefit plans and arrangements sponsored by Regency GP LLC or its affiliates, including plans that may be established in the future.

Our chief executive officer and our chief operating officer were employed by Regency Gas Services LLC on December 1, 2004. Each of our three other most highly compensated executive officers were employed by Regency Gas Services LLC on January 1, 2005 or later. All these officers now hold the same positions with Regency GP LLC. The following table sets forth the rates of compensation paid to our chief executive officer and our four other most highly compensated executive officers by Regency GP LLC during 2005, which are the same rates at which these officers were compensated by Regency Gas Services LLC through January 2006. We refer to these executives as the named executive officers elsewhere in this report.

Summary Compensation Table

	Annual Compensation		**Long-Term Compensation**		**All Other Compensation**
Name and Principal Position	**Annual Salary and Bonuses ($) (1)**	**Other Compensation ($) (2)(3)**	**Restricted Common Units ($)**	**Underlying Options (Units)**	
James W. Hunt President, Chief Executive Officer and Chairman of the Board	$ 246,000	$ 4,200		100,000	
Michael L. Williams Executive Vice President and Chief Operating Officer	215,250	3,675		40,000	
Stephen L. Arata Executive Vice President and Chief Financial Officer	205,000			35,000	
William E. Joor III Executive Vice President and Chief Legal and Administrative Officer	205,000	3,500		35,000	
Alvin Suggs Vice President and General Counsel	184,500	2,700		15,000	

(1) The board of directors of Regency Gas Services LLC adopted the Regency Gas Services LLC Annual Performance Incentive Plan (or the Annual Incentive Plan) in May 2005. Substantially all our employees, including each of the named executive officers, are participants in the Annual Incentive Plan. Regency GP LLC has adopted and continued the plan. The Compensation Committee of Regency Gas Services LLC has been

directed to administer the Annual Incentive Plan and, in awarding bonuses, the Compensation Committee considered a number of factors, including annual personal and company performance goals. These amounts include small advances of the bonuses that were awarded in March 2006 but paid as Christmas bonuses in December 2005. The amount of the March 2006 awards not included in the above table are as follows: Mr. Hunt $134,583; Mr. Williams $117,760; Mr. Arata $63,339; Mr. Joor $94,580; Mr. Suggs $95,500. Upon the completion of our initial public offering in February 2006, the board of directors of Regency GP LLC approved salary levels for 2006 in the following amounts: Mr. Hunt $400,000; Mr. Williams $300,000; Mr. Arata $250,000; and Mr. Joor $215,000. The amounts paid pursuant to these salary levels will be prorated from completion of the initial public offering to December 31, 2006.

(2) These amounts include the contributions of Regency Gas Services LLC to our Section 401(k) plan for the entire year.

(3) These amounts do not include perquisites because the aggregate amount of such benefits does not exceed either $50,000 or 10% of the total of annual salary and bonus reported for the respective officers.

(4) Regency GP LLC has adopted a Long Term Incentive Plan. Please read the description of the plan under Long Term Incentive Plan.

(5) All options have an exercise price of $20 per unit (equal to the initial public offering price) and vest and may be exercised in one-third increments on the anniversary of the grant date over a period of three years.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires executive officers, directors and persons who beneficially own more than ten percent of a security registered under Section 12 of the Securities Exchange Act of 1934 to file initial reports of ownership and reports of changes of ownership of such security with the Securities and Exchange Commission. 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 Securities Exchange Act on January 30, 2006. Accordingly, no reports under Section 16(a) were required to be filed with respect to any securities of the Partnership during the fiscal year ended December 31, 2005.

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

The following table sets forth, as of March 15, 2006, the beneficial ownership of our units by:

each person who then owned beneficially 5% 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.

Ownership information regarding the common and subordinated units set forth in the following table is derived from:

the holdings thereof by HMTF Regency, L.P. and the resulting economic interest therein of the persons named in the table pursuant to their ownership of Class A Units of HMTF Regency, L.P.; or

the exchange of Class B Units and Class D Units of net profits interests in HMTF Regency, L.P. held by persons named in the table prior to the IPO for common and subordinated units.

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These transactions are described in detail under Certain Relationships and Related Party Transactions Limited Partner Interests to be Received by Certain Members of Management and Limited Partner Interests to be Received by Certain Directors.

Name of Beneficial Owner	Common Units	Percentage of Outstanding Common Units(7)	Subordinated Units	Percentage of Outstanding Subordinated Units(7)	Percentage of Total Units
Regency Acquisition LP(1)	3,456,255	18.1%	16,699,462	87.4%	52.8%
John R. Muse(1)	3,506,255	18.4	16,699,462	87.4	52.9
James W. Hunt(2)(3)(5)	73,993	0.4	840,678	4.4	2.4
Michael L. Williams(2)(3)(5)	99,425	0.5	480,387	2.5	1.5
Stephen L. Arata(2)(3)(5)	49,712	0.3	240,194	1.3	0.8
William E. Joor III(2)(3)(5)	74,569	0.4	360,290	1.9	1.1
Durell J. Johnson(2)(3)(5)	14,914	0.1	72,058	0.4	0.2
Lawrence B. Connors(2)(3)(5)	14,914	0.1	72,058	0.4	0.2
Alvin Suggs(2)(3)(5)	14,914	0.1	72,058	0.4	0.2
Charles M. Davis Jr.(6)	100,000	0.5	0	0.0	0.3
Joe Colonnetta(1)	25,000	0.1	0	0.0	0.1
Jason H. Downie(1)	11,000	0.1	0	0.0	Note(8)
A. Dean Fuller	12,500	0.1	0	0.0	Note(8)
Jack D. Furst(1)	12,500	0.1	0	0.0	Note(8)
J. Edward Herring(1)	10,000	0.1	0	0.0	Note(8)
Robert D. Kincaid(4)(5)	12,715	0.1	37,278	0.2	0.1
Gary W. Luce(4)(5)	12,715	0.1	37,278	0.2	0.1
J. Otis Winters	10,000	0.1	0	0.0	Note(8)
Robert W. Shower	10,000	0.1	0	0.0	Note(8)
All directors and executive Officers as a group (16 persons)	4,015,126	21.0%	18,911,741	99.0%	60.0%

(1) According to Schedule 13D/ A (Amendment No. 1) dated March 8, 2004 (the Schedule 13D) filed jointly by Regency Acquisition LP, a Delaware limited partnership (Acquisition); Regency Holdings LLC, a Delaware limited liability company and the general partner of Acquisition (Holdings); HMTF Regency, L.P., a Delaware limited partnership which is the sole member of Holdings and owns all of the limited partnership interest in Acquisition (HMTF Regency); HMTF Regency, L.L.C., a Texas limited liability company and the general partner of HMTF Regency (HMTF GP); Hicks, Muse, Tate & Furst Equity Fund V, L.P., a Delaware limited partnership and the sole member of HMTF GP (Fund V); HM5/ GP LLC, a Texas limited liability company, the general partner of Fund V (HM5); and John R. Muse, a member and the sole manager of HM5 (Muse and, together with Acquisition, Holdings, HMTF Regency, HMTF GP, Fund V and the General Partner (collectively, the HMTF Entities), the 13D Parties). Acquisition is the record and beneficial owner of 3,456,255 common units and 16,699,462 subordinated units. As a result of Muse being the sole manager of the HM5 and the relationship of HM5 to Fund V, Fund V to HMTF GP, HMTF GP to HMTF Regency, HMTF Regency to Holdings, and Holdings to Acquisition, each 13D Party may be deemed to have shared power to vote, or direct the disposition of, and to dispose, or direct the disposition of, the common units and subordinated units held of record by Acquisition. Muse also is the record owner of 50,000 common units and has sole power to vote or direct the vote and the power to

dispose or direct the disposition of the common units owned of record by him. Each of the HMTF Entities disclaims beneficial ownership of the common units held of record by Muse.

(2) Each of these executive officers disclaims beneficial ownership of any common and subordinated units held by HMTF Regency, L.P. resulting from his ownership of Class A Units of HMTF Regency, L.P. by each such person as he does not have voting or dispositive control of these units. These units include the following: Mr. Hunt 18,817 common and 90,920 subordinated; Mr. Williams 4,897 common and 23,659 subordinated; Mr. Arata 4,897 common and 23,659 subordinated; Mr. Joor 4,897 common and 23,659 subordinated; Mr. Johnson 1,959 common and 9,464 subordinated; Mr. Connors 4,897 common and 23,659 subordinated; and Mr. Suggs 1,959 common and 9,464 subordinated. Each of these executive officers will be treated as regards his ownership of Class A Units, in the same manner as any other HM Capital Investor. The address of each of these individuals is 1700 Pacific, Suite 2900, Dallas, Texas 75201.

(3) The remaining common and subordinated units owned beneficially by these individuals were acquired on exchange of Class B Units of HMTF Regency, L.P. in the manner described under Certain Relationships and Related Party Transactions Partnership Interests to be Received by Executive Officers.

(4) Each of these directors disclaims beneficial ownership of any common and subordinated units held by HMTF Regency, L.P. resulting from his ownership of Class A Units of HMTF Regency L.P. by each such person as he does not have voting or dispositive control of these units. These units include the following: Mr. Luce 4,897 common and 23,659 subordinated; and Mr. Kincaid 4,897 common and 23,659 subordinated. Each of these directors will be treated, as regards his ownership of Class A Units, in the same manner as any other HMTF Investor. The address of each of these individuals is 1700 Pacific, Suite 2900, Dallas, Texas 75201.

(5) At the time of consummation of our initial public offering, each of these individuals exchanged Class B or Class D Units in HMTF Regency, L.P. for common and subordinated units as described in note (3) and for Class E Units of HMTF Regency, L.P. The Class E Units evidence the pecuniary interests of the holders in the general partner interest in our General Partner, Regency GP LP, owned indirectly by HMTF Regency, L.P. As a result of their holdings of both Class A and Class E Units in HMTF Regency, L.P., the following named individuals own the indicated percentages of undivided general partner interest in our General Partner: Mr. Hunt 3.2%; Mr. Williams 1.6%; Mr. Joor 1.3%; Mr. Arata 0.9%; Mr. Connors 0.4%; Mr. Johnson 0.3%; Mr. Suggs 0.3%; Mr. Kincaid 0.2%; Mr. Luce 0.2%.

(6) Mr. Davis was elected an officer on March 21, 2006 and commenced employment in March 2006.

(7) The number of Common and Subordinated units outstanding are 19,103,896 each.

(8) Ownership percentages are less than .1%.

ITEM 13. Certain Relationships and Related Transactions

Our general partner and its affiliates own 3,953,896 common units and 19,103,896 subordinated units representing a 59.1% limited partner interest in us. In addition, our general partner owns a 2% general partner interest in us and the incentive distribution rights.

Distributions and Payments to Our General Partner and Its Affiliates

The following table summarizes the distributions and payments to be made by us to our general partner and its affiliates in connection with the formation, ongoing operation and any liquidation of the Partnership. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm s-length negotiations.

FORMATION STAGE	
The consideration received by our general partner and its affiliates for the contribution of the assets and liabilities to us	5,353,896 common units;
	19,103,896 subordinated units;
	2% general partner interest;
	the incentive distribution rights; and
OPERATIONAL STAGE	
Distributions of available cash to our general partner and its affiliates	We will generally make cash distributions of 98% to the unitholders pro rata, including our general partner and its affiliates, as the holders of an aggregate 3,953,896 common units and 19,103,896 subordinated units, and 2% to our general partner. In addition, if distributions exceed the minimum quarterly distribution and other higher target distribution levels, our general partner will be entitled to increasing percentages of the distributions, up to 50% of the distributions that exceed the highest target level.

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	Assuming we have sufficient available cash to pay the full minimum quarterly distribution on all of our outstanding units for four quarters, our general partner and its affiliates would receive an annual distribution of approximately $1.1 million on its 2% general partner interest and $32.3 million on their common and subordinated units.
Payments to our general partner and its affiliates	Our general partner and its affiliates will be entitled to reimbursement for all expenses it incurs on our behalf, including salaries and employee benefit costs for its employees who provide services to us, and all other necessary or appropriate expenses allocable to us or reasonably incurred by our general partner and its affiliates in connection with operating our business. The partnership agreement provides that our general partner will determine the expenses that are allocable to us in good faith.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests. Please read The Partnership Agreement Withdrawal or Removal of the General Partner.
	LIQUIDATION STAGE
Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Agreements Governing the Transactions

We and other parties have entered into the various documents and agreements pursuant to which we effected the offering transactions, including the vesting of assets in, and the assumption of liabilities by, us and our subsidiaries, and the application of the proceeds of our initial public offering. These agreements were not the result of arm s-length negotiations, and they, or any of the transactions that they provide for, may not have been effected on terms at least as favorable to the parties to these agreements as could have been obtained from unaffiliated third parties. All of the transaction expenses incurred in connection with these transactions, including the expenses associated with transferring assets into our subsidiaries, were paid from the proceeds of our initial public offering.

Omnibus Agreement

Upon the closing of our initial public offering, we entered into an omnibus agreement with Regency Acquisition LP pursuant to which Regency Acquisition LP agreed to indemnify us against certain environmental and related liabilities arising out of or associated with the operation of the assets before the consummation of our initial public offering. This indemnification obligation will terminate on February 3, 2009. There is an aggregate cap of $8.6 million on the amount of indemnity coverage for environmental and related liabilities. In addition, we are not entitled to indemnification until the aggregate amount of all claims under the omnibus agreement exceed $250,000. Liabilities resulting from a change of law after the offering are excluded from the environmental indemnity by Regency Acquisition LP for the unknown environmental liabilities.

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Regency Acquisition LP has also indemnified us for liabilities related to:

- certain defects in the easement rights or fee ownership interests in and to the lands on which any assets contributed to us are located and failure to obtain certain consents and permits necessary to conduct our business that arise within two years after the closing of the IPO; and

- certain income tax liabilities attributable to the operation for the assets contributed to us prior to the time they were contributed.

Amendments

The omnibus agreement may not be amended without the prior approval of the conflicts committee if the proposed amendment will, in the reasonable discretion of our general partner, adversely affect holders of our common units.

Competition

Regency Acquisition LP will not be restricted under the omnibus agreement from competing with us. Regency Acquisition LP may acquire, construct or dispose of 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.

Limited Partner Interests Received by Certain Members of Management

Regency Gas Services LLC was acquired in December 2004 by the HM Capital Investors through the use of a Delaware limited partnership HMTF Regency, L.P. The HM Capital Investors purchased units of limited partnership interests (Class A Units) in HMTF Regency, L.P. for cash, which was used to provide part of the purchase price for Regency Gas Services LLC. The HM Capital Investors include the executive officers of Regency Gas Services LLC and now Regency GP LLC, each of whom purchased Class A Units of HMTF Regency, L.P. on the same terms as each other HMTF Investor.

At the time of the acquisition, two members of our management, the Chief Executive Officer and the Chief Operating Officer, were awarded net profits interests in the form of Class B Units in HMTF Regency, L.P. Subsequently, our Chief Legal Officer, Chief Financial Officer and other executive officers were also awarded Class B Units.

The Class B Units were designed to provide incentives to management to enhance the value of the investment by HMTF Regency, L.P. in Regency Gas Services LLC represented by the Class A Units. Under the partnership agreement, the economic benefit of the Class B Units was to be conferred at the time of liquidation and sale of the investment for cash and the distribution of the cash to the holders of both Class A Units and Class B Units. The partnership agreement provides for distributions to be made to the holders of the Class B Units only after the holders of Class A Units have received distributions equal to a return of 150% of the investment by those holders in Class A Units or, alternatively, various rates of return on investment.

The consummation of our initial public offering and the related formation transactions did not result in the liquidation of Regency Gas Services LLC. They did, however, result in realization of value by the holders of the Class A Units as a result of the receipt by HMTF Regency, L.P. of common and subordinated units and interests in our general partner. Consequently, the general partner of HMTF Regency, L.P. (through Regency Acquisition LP, its wholly owned subsidiary) determined that the common units, subordinated units and general partner interests to be received by HMTF Regency, L.P. as a result of those transactions should be allocated among the holders of the Class A Units and Class B Units as if HMTF Regency, L.P. were to be liquidated in accordance with the partnership agreement.

As a result of the consummation of our initial public offering, HMTF Regency, L.P. received common and subordinated units issued by us, as well as interests in our general partner. Those units and interests were allocated between the holders of the Class A Units and Class B Units based on the partnership agreement liquidation provisions as follows:

The total number of common and subordinated units and general partner interests issued or transferred to HMTF Regency, L.P. were valued at the initial offering price per common unit ($20.00).

From that aggregate number of units and interests, a number of units and interests with an equivalent value of $320.6 million (representing a 150% return on the aggregate investment in Class A Units plus transaction expenses) were allocated to the Class A Unit holders.

Of the remainder, 87.5% were allocated to the Class A Unit holders and 12.5% were allocated to the Class B Unit holders as a group.

The common and subordinated units allocated to the holders of Class A Units will continue to be held by HMTF Regency, L.P.

The common and subordinated units allocated to the holders of Class B Units were distributed to those holders in exchange for their Class B Units.

The common and subordinated units and interests so distributed to the group of Class B Unit holders were allocated among the group in accordance with their respective holdings of Class B Units.

Common and subordinated units and interests were allocated to the Class B Unit holders in the same percentages as those held for the benefit of the Class A Unit holders.

As a result of the application of these allocation procedures, our executive officers as a group received an aggregate of 442,441 common units and 2,137,723 subordinated units in exchange for their Class B Units and have an indirect economic interest in an aggregate of 42,323 common units and 204,484 subordinated units by virtue of their continued ownership of Class A Units. Please see the table under Security Ownership of Certain Beneficial Owners and Management for the numbers of common and subordinated units received by each of the named executive officers of Regency GP LLC.

The formula for allocation of common and subordinated units of Regency Energy Partners LP among the holders of Class A Units and Class B Units of HMTF Regency, L.P. established by the general partner of HMTF Regency, L.P. was predicated on the indicative aggregate market capitalization of Regency Energy Partners LP based on the initial public offering price of common units.

As a result of distributions of the net proceeds from our initial public offering to the HM Capital Investors, certain of our officers received, by virtue of their holdings of Class A Units and Class C Units of HMTF Regency, L.P., an aggregate of approximately $3,300,000.

Limited Partner Interests Received by Certain Directors

Robert D. Kincaid and Gary W. Luce, who were elected as directors of Regency Gas Services LLC at the time of its acquisition by HMTF Regency, L.P., were awarded net profits interests in the form of Class D Units in HMTF Regency, L.P. as an incentive to serve as directors. Those Class D Units were converted into and exchanged for common and subordinated units and general partner interests on the same basis as Class B Units, except that the allocation between Class A Units and Class D Units was on the basis of 99.6% and 0.4%, respectively. As a result of the application of these allocation procedures, these two directors together received an aggregate of 15,430 common units and 74,556 subordinated units in exchange for their Class D Units and have an economic interest in an aggregate of 9,794 common units and 47,318 subordinated units by virtue of their continued ownership of Class A Units. Please see the table under Security Ownership of Certain Beneficial Owners and Management for the numbers of common and subordinated units and general partner interests received by each director.

As a result of distributions of the net proceeds from the IPO to the HM Capital Investors, Messrs. Kincaid and Luce together received, by virtue of their holdings of Class A Units of HMTF Regency, L.P., an aggregate of approximately $765,000.

General Partner Interests

The HM Capital Investors, our executive officers and Messrs. Kincaid and Luce together own economic interests in our general partner of 91.6%, 7.9% and 0.5%, respectively, as a result of their ownership of Class A Units and Class E Units in HMTF Regency, L.P.

Related Party Transactions with the HM Capital Investors

On December 1, 2004, the HM Capital Investors acquired 100% of the outstanding member interests of Regency Gas Services LLC from Regency Services LLC and became the single member owner of Regency Gas Services LLC. In connection with this acquisition, we entered into a financial advisory agreement and a monitoring and oversight agreement with an affiliate of HM Capital. The financial advisory agreement designated an affiliate of HM Capital to be our exclusive financial advisor in connection with any subsequent transactions (as such term is defined in the financial advisory agreement). The monitoring and oversight agreement provided that an affiliate of HM Capital will provide us with financial oversight and monitoring services. Each agreement had a term of the earlier of 10 years or until HM Capital or its successors or affiliates no longer owns securities of Regency Gas Services.

Upon the completion of the acquisition by the HM Capital Investors and pursuant to the financial advisory agreement, an advisory transaction fee of approximately $6 million was paid to the affiliate of HM Capital. This amount was included in the purchase price and was allocated to the assets. In addition, Regency Gas Services LLC paid management and financial advisory fees in the amount of approximately $1.1 million to the affiliate of HM Capital in the year ended December 31, 2005, and less than $0.1 million for the month of December 2004.

At the closing of our initial public offering and the related formation transactions, we paid $9.0 million to an affiliate of HM Capital as consideration for the termination of the ten-year financial advisory and monitoring and oversight agreements between the affiliate of HM Capital and us. These agreements would have required us to pay to the affiliate of HM Capital certain management fees and transaction advisory fees in the future, which would decrease our cash available for distribution. We will continue to be obligated to indemnify HM Capital, its affiliates, and their respective directors, officers, controlling persons, agents and employees from all claims, liabilities, loses, damages, expenses and fees and disbursements of counsel related to or arising out of or in connection with the services rendered under these agreements and not resulting primarily from bad faith or willful misconduct.

Following our initial public offering, the HM Capital Investors own 3,953,896 common units and 19,103,896 subordinated units representing a 60.3% limited partner interest in us, as well as the 2.0% general partner interest.

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ITEM 14. Principal Accounting Fees and Services

The following set forth fees billed by Deloitte & Touche LLP for the audit of our annual financial statements and other services rendered for the fiscal years ended December 31, 2005 and 2004:

	December 31,	
	2005	2004
Audit fees(1)	$ 1,180,000	$ 234,000
Audit related fees(2)	60,000	
Tax fees(3)	53,000	164,000
All other fees(4)		
Total	$ 1,293,000	$ 398,000

(1) Includes fees for audits of annual financial statements of our companies (as well as an audit of our financial statements at June 30, 2005 in connection with our initial public offering), reviews of the related quarterly financial statements, and services that are normally provided by the independent accountants in connection with statutory and regulatory filings or engagements, including reviews of documents filed with the Securities and Exchange Commission.

(2) Includes fees related to consultations concerning financial accounting and reporting standards and services related to the implementation of our internal controls over financial reporting.

(3) Includes fees related to professional services for tax compliance, tax advice, and tax planning. These tax services were incurred on behalf of HMTF Regency, L.P. for the years ended December 31, 2004 and 2005.

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

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 Deloitte & Touch LLP, including audit services, audit-related services, tax services and other services, must be pre-approved by the 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, Financial Statement Schedules.

(a) 1. Financial Statements.

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

2. Financial Statement Schedules.

None.

3. Exhibits.

See Index to Exhibits set forth on page E-1.

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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/ James W. Hunt

James W. Hunt
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/ James W. Hunt James W. Hunt	Chairman, President, and Chief Executive Officer (Principal Executive Officer)	March 30, 2006
/s/ Stephen L. Arata Stephen L. Arata	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 30, 2006
/s/ Lawrence B. Connors Lawrence B. Connors	Vice President, Finance and Accounting (Principal Accounting Officer)	March 30, 2006
/s/ Joe Colonnetta Joe Colonnetta	Director	March 30, 2006
/s/ Jason H. Downie Jason H. Downie	Director	March 30, 2006
/s/ A. Dean Fuller A. Dean Fuller	Director	March 30, 2006
/s/ Jack D. Furst Jack D. Furst	Director	March 30, 2006

/s/ J. Edward Herring	Director	March 30, 2006
J. Edward Herring		

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Signature	Title	Date
/s/ Robert D. Kincaid Robert D. Kincaid	Director	March 30, 2006
/s/ Gary W. Luce Gary W. Luce	Director	March 30, 2006
/s/ Robert W. Shower Robert W. Shower	Director	March 30, 2006
/s/ J. Otis Winters J. Otis Winters	Director	March 30, 2006

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INDEX TO EXHIBITS

Exhibit Number	Description
3.1*	Certificate of Limited Partnership of Regency Energy Partners LP
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)
3.3*	Certificate of Formation of Regency GP LLC
3.4*	Form of Amended and Restated Limited Liability Company Agreement of Regency GP LLC
3.5*	Certificate of Limited Partnership of Regency GP LP
3.6*	Form of Amended and Restated Limited Partnership Agreement of Regency GP LP
4.1*	Form of Common Unit Certificate
10.1*	Amended and Restated Credit Agreement of Regency Gas Services LLC
10.2*	Amended and Restated Second Lien Credit Agreement of Regency Gas Services LLC
10.3*	Second Amended and Restated Credit Agreement of Regency Gas Services LLC
10.4*	Regency GP LLC Long-Term Incentive Plan
10.5*	Form of Grant Agreement for the Regency GP LLC Long-Term Incentive Plan Unit Option Grant
10.6*	Form of Grant Agreement for the Regency GP LLC Long-Term Incentive Plan Restricted Unit Grant
10.7*	Form of Grant Agreement for the Regency GP LLC Long-Term Incentive Plan Phantom Unit Grant (With DERS)
10.8*	Form of Grant Agreement for the Regency GP LLC Long-Term Incentive Plan Phantom Unit Grant (Without DERS)
10.9*	Form of Contribution, Conveyance and Assumption Agreement
10.10*	Executive Employment Agreement dated December 1, 2004 between the Registrant and James W. Hunt
10.11*	Employment Agreement dated December 1, 2004 between the Registrant and Michael L. Williams
10.12*	Severance Agreement dated January 1, 2005 between the Registrant and William E. Joor, III
10.13*	Purchase Agreement by and among Regency Acquisition LLC, Regency Services, LLC, Regency Gas Services LLC, the Members of Regency Services, LLC and the Partners of CB Offshore Equity Fund V Holdings, L.P. dated October 21, 2004.
10.14*	Purchase and Sale Agreement between Duke Energy Field Services, LP and Regency Gas Services Waha, LP Dated January 29, 2004
10.15*	Pipeline Construction Contract between Regency Gas Services LLC and H.C. Price dated May 2, 2005 (relating to construction of 30 natural gas pipeline with facilities in Louisiana)
10.16*	Pipeline Construction Contract between Regency Intrastate Gas LLC and H.C. Price Co. dated May 2nd, 2005 (relating to the construction of 24 natural gas pipeline with facilities in Louisiana)
10.17*	Ground Lease Agreement (Lakin Plant)
10.18*	Ground Lease Agreement (Mocane Plant)
10.19*	Lisbon Lease Agreement

10.20*	Firm Transportation Agreement dated June 8, 2005 between Regency Intrastate Gas LLC and Anadarko Energy Services Company
10.21*	Form of Third Amended and Restated Credit Agreement of Regency Gas Services LLC
10.22*	Form of Indemnification Agreement between Regency GP LLC and Indemnitees
10.23*	Financial Advisory Agreement

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Exhibit Number	Description
10.24*	Monitoring and Oversight Agreement
10.25*	Form of Omnibus Agreement
21.1*	List of Subsidiaries of Regency Energy Partners LP
31.1	Certifications pursuant to Rule 13a-14(a).
31.2	Certifications pursuant to Rule 13a-14(a).
32.1	Certifications pursuant to Section 1350.
32.2	Certifications pursuant to Section 1350.
99.1	Financial Statements of Regency GP LP, the general partner of the registrant.
*	Incorporated by reference to the comparably numbered exhibit to the registrant s registration statement on Form S-1 (File No. 333-128332).
	Portions of this exhibit have been omitted pursuant to a request for confidential treatment.

INDEX TO CONSOLIDATED FINANCIAL INFORMATION

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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 balance sheet of Regency Energy Partners LP (the Partnership) as of December 31, 2005. The financial statement is the responsibility of the Partnership s management. Our responsibility is to express an opinion on the financial statement 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 provides a reasonable basis for our opinion.

In our opinion, the balance sheet presents fairly, in all material respects, the financial position of the Partnership as of December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Dallas, Texas
March 30, 2006

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Regency Energy Partners LP
Balance Sheet as of December 31, 2005

	December 31, 2005	
Assets		
Cash	$	1,000
Total assets		1,000
Partners Equity		
Limited partner s equity	$	980
General partner s equity		20
Total partners equity	$	1,000

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Regency Energy Partners LP
Notes to Balance Sheet
December 31, 2005

Regency Energy Partners LP (the Partnership), is a Delaware limited partnership formed on September 8, 2005, to acquire all of the member interest of Regency Gas Services LLC (Predecessor). The Partnership is engaged in gathering, processing, marketing, and transporting natural gas and natural gas liquids. The Partnership s general partner is Regency GP LP.

Initial Public Offering On September 15, 2005, a Registration Statement on Form S-1 (File No. 333-128332) was filed with the United States Securities and Exchange Commission (the SEC) relating to a proposed underwritten initial public offering (IPO) of limited partnership interests in Regency Energy Partners LP. On January 30, 2006, the Partnership priced 13,750,000 common units, representing a 35.3% limited partner interest in the Partnership, for the initial public offering and on January 31, 2006 the Partnership s common units began trading on the NASDAQ National Market under the symbol RGNC. On February 3, 2006, the Partnership closed its initial public offering of 13,750,000 common units at a price of $20.00 per unit. Total proceeds from the sale of the units were $275 million, before offering costs and underwriting commissions.

The assets of the Predecessor were contributed to the Partnership by Regency Acquisition LP (Acquisition) in exchange for 19,103,896 subordinated units representing a 49% limited partner interest in the Partnership; 5,353,896 common units representing a 13.7% limited partner interest in the Partnership; a 2% general partner interest in the Partnership; incentive distribution rights; and the right to receive reimbursement of approximately $196 million of capital expenditures comprising most of the initial investment by HM Capital Partners LLC (HM Capital) in Regency Gas Services LLC. Concurrent with the closing of the IPO, Regency Gas Services LLC was converted to a limited partnership.

The proceeds of the Partnership s initial public offering were used to: distribute approximately $196 million to HMTF Regency LP (the Parent) for reimbursement of capital expenditures and to replenish $48 million of working capital assets which were distributed to HM Capital immediately prior to the IPO; pay $9 million to an affiliate of the Parent to terminate a management services contract; and pay $22 million of underwriting commissions, structuring fees and other offering costs.

On March 8, 2006, the Partnership closed the sale of an additional 1,400,000 common units at a price of $20 per unit as the underwriters exercised a portion of their over allotment option. The net proceeds from the sale were used by us to redeem an equivalent number of common units held by Regency Acquisition LP for the benefit of the HM Capital Investors, reducing their partner interest to 61.1%.

Omnibus Agreement Upon the closing of the Partnership s IPO, the Partnership entered into an omnibus agreement with Acquisition in which Acquisition indemnifies the Partnership against certain environmental and related liabilities arising out of or associated with the operation of the assets preceding the IPO closing date. The environmental liability indemnification is limited to $8.6 million with a deductible of $250,000 and terminates after three years. In addition, the omnibus agreement indemnifies the Partnership against certain defects in the easement rights or fee ownership interests in and to the lands on which any assets contributed to it are located, and failure to obtain certain consents and permits necessary to conduct the business that arise within two years. Further, the omnibus agreement indemnifies the Partnership against certain income tax liabilities attributable to the operation of the contributed assets prior to the closing of the IPO.

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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 balance sheets of Regency Gas Services LLC (Predecessor) and subsidiaries (the Company) as of December 31, 2005 and 2004, and the related consolidated statements of operations, changes in member interest, and cash flows for the year ended December 31, 2005, the period from acquisition date (December 1, 2004) to December 31, 2004, and Regency LLC Predecessor for the period from January 1, 2004 to November 30, 2004 and for the period from inception (April 2, 2003) to December 31, 2003. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits 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 Company 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 audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2005 and 2004, and the results of the Company s operations and cash flows for the year ended December 31, 2005, period from acquisition date (December 1, 2004) to December 31, 2004 and the results of Regency LLC Predecessor s operations and cash flows for the period from January 1, 2004 to November 30, 2004 and the period from inception (April 2, 2003) to December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Dallas, Texas
March 30, 2006

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Regency Gas Services LLC (Predecessor)
Consolidated Balance Sheets
($ in thousands)

	Regency Gas Services LLC	
	December 31, 2005	**December 31, 2004**
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 3,669	$ 3,272
Restricted cash	5,533	5,410
Accounts receivable, net of allowance of $169 in 2005 and $135 in 2004	78,782	49,215
Assets from risk management activities	1,717	2,767
Other current assets	3,950	2,713
Total current assets	93,651	63,377
Property, plant and equipment		
Gas plants and buildings	46,399	44,606
Gathering and transmission systems	397,481	250,392
Other property, plant and equipment	41,470	20,427
Construction-in-progress	16,738	14,380
Total property, plant and equipment	502,088	329,805
Less accumulated depreciation	(21,505)	(1,457)
Property, plant and equipment, net	480,583	328,348
Intangible and other assets		
Intangible assets, net of amortization	16,370	18,342
Goodwill	57,552	58,529
Assets held for sale		4,101
Long-term assets from risk management activities	1,333	6,243
Other, net of amortization on debt issuance costs of $271 in 2005 and $112 in 2004	4,835	7,549
Total intangible and other assets	80,090	94,764
TOTAL ASSETS	$ 654,324	$ 486,489
LIABILITIES & MEMBER INTEREST		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 99,745	$ 51,471
Escrow payable	5,533	5,410
Accrued taxes payable	2,266	1,460
Interest payable	67	
Liabilities from risk management activities	11,312	14

Current portion of long term debt		2,000
Other current liabilities	2,378	1,170
Total current liabilities	121,301	61,525
Long term liabilities from risk management activities	4,895	
Long-term debt	358,350	248,000
Commitments and contingencies		
Member interest	169,778	176,964
TOTAL LIABILITIES & MEMBER INTEREST	$ 654,324	$ 486,489

See accompanying notes to consolidated financial statements.

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Regency Gas Services LLC (Predecessor)
Consolidated Statements of Operations
($ in thousands)

	Regency Gas Services LLC		Regency LLC Predecessor	
	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	Period from Inception (April 2, 2003) to December 31, 2003
REVENUE				
Gas sales	$ 495,987	$ 32,616	$ 279,582	$ 127,149
NGL sales	179,305	11,890	123,827	46,697
Gathering, transportation and other fees	25,921	1,943	19,016	9,439
Unrealized/realized gain/(loss) from risk management activities	(22,243)	322		
Other	13,633	1,070	9,896	3,248
Total revenue	692,603	47,841	432,321	186,533
EXPENSE				
Cost of gas and liquids	611,137	39,979	352,508	158,524
Other cost of sales	9,614	1,007	10,254	4,937
Operating expenses	21,812	1,819	17,786	7,012
General and administrative	14,412	638	6,571	2,651
Transaction expenses			7,003	724
Depreciation and amortization	22,010	1,613	10,129	4,324
Total operating expense	678,985	45,056	404,251	178,172
OPERATING INCOME	**13,618**	**2,785**	**28,070**	**8,361**
OTHER INCOME AND DEDUCTIONS				
Interest expense, net	(17,432)	(1,335)	(5,097)	(2,392)
Loss on debt refinancing	(8,480)		(3,022)	
Other income and deductions, net	338	14	186	205
Total other income and deductions	(25,574)	(1,321)	(7,933)	(2,187)
NET (LOSS) INCOME FROM CONTINUING OPERATIONS	**(11,956)**	**1,464**	**20,137**	**6,174**
DISCONTINUED OPERATIONS				
Income (loss) from operations of Regency Gas Treating LP (including gain on disposal of $626 in 2005; Note 2)	732		(121)	
NET (LOSS) INCOME	**$ (11,224)**	**$ 1,464**	**$ 20,016**	**$ 6,174**

See accompanying notes to consolidated financial statements.

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Regency Gas Services LLC (Predecessor)
Consolidated Statement of Changes in Member Interest
For the Periods from Inception (April 2, 2003) to December 31, 2005
($ in thousands)

	Comprehensive Income (Loss)	Accumulated Other Comprehensive Income (Loss)	Member Interest
Regency LLC Predecessor			
Member interest contribution June 2, 2003	$		$ 53,750
Net income for the period from inception (April 2, 2003) to December 31, 2003	6,174		6,174
Member interest distributions			(68)
Comprehensive Income	$ 6,174		
Balance, December 31, 2003			59,856
Member interest contribution March 1, 2004			10,000
Net income for the period from January 1, 2004 to November 30, 2004	20,016		20,016
Comprehensive Income	$ 20,016		
Balance, November 30, 2004			89,872
Member interest distributions			(89,872)
Balance, December 1, 2004			$
Regency Gas Services LLC			
Net consideration paid by the HM Capital Investors	$		$ 171,000
Member interest contribution December 2004			4,500
Net income for the period from December 1, 2004 to December 31, 2004	1,464		1,464
Comprehensive Income	$ 1,464		
Balance, December 31, 2004	$		176,964
Member interest contribution July 25, 2005			15,000
Net loss for the year ended December 31, 2005	(11,224)		(11,224)
Other Comprehensive Income (Loss):			
Net change in fair value of cash flow hedges	(16,502)	(16,502)	
Amounts reclassified to earnings during the period	5,540	5,540	
Other Comprehensive Loss	(10,962)		(10,962)
Comprehensive Loss	$ (22,186)		

Balance, December 31, 2005	$	(10,962)	$ 169,778

See accompanying notes to consolidated financial statements.

Regency Gas Services LLC (Predecessor)
Consolidated Statements of Cash Flows
($ in thousands)

	Regency Gas Services LLC		Regency LLC Predecessor	
	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	Period from Inception (April 2, 2003) to December 31, 2003
OPERATING ACTIVITIES				
Net income (loss)	$ (11,224)	$ 1,464	$ 20,016	$ 6,174
Adjustments to reconcile net income to net cash flows provided (used) by operations:				
Depreciation & amortization	23,092	1,745	10,461	4,658
Loss on debt refinancing	8,480		3,022	
Risk management portfolio valuation changes	11,191	(322)		
Gain on the sale of Regency Gas Treating LP assets	(626)			
Gain on the sale of NGL line pack	(628)			
Cash flows impacted by changes in				
Current assets and liabilities:				
Accounts receivable	(29,567)	2,583	(20,408)	(31,390)
Advances to affiliates			576	(576)
Other current assets	(1,237)	(2,430)	(1,169)	(1,070)
Accounts payable and accrued liabilities	32,722	(155)	18,122	26,880
Accrued taxes payable	806	(921)	1,475	906
Interest payable	67	(541)	398	143
Distributions payable			(69)	68
Other current liabilities	1,208	293	173	706
Other assets	(3,263)	(6,646)	(196)	(5)
Net cash flows provided (used) by operating activities	**31,021**	**(4,930)**	**32,401**	**6,494**
INVESTING ACTIVITIES				
Capital expenditures	(151,486)	(2,143)	(15,092)	(3,624)
Cash outflows for acquisition by HM Capital Investors	(5,808)	(127,804)		
Proceeds from sale of Regency Gas Treating LP assets	6,000			

Proceeds from sale of NGL line pack		1,099						
Purchase of El Paso properties								(119,541)
El Paso escrow adjustment						1,168		
Cardinal acquisition						(3,533)		
Purchase of Waha properties						(67,264)		
Net cash flows used in investing activities		**(150,195)**		**(129,947)**		**(84,721)**		**(123,165)**
FINANCING ACTIVITIES								
Borrowings under credit facilities		60,000		250,000		45,363		70,000
Repayments under credit facilities		(1,650)		(101,471)		(10,492)		(3,401)
Net borrowings under revolving credit facilities		50,000		(13,000)		13,000		
Debt issuance costs		(3,779)		(7,514)		(1,491)		(2,036)
Member interest contributions		15,000		4,500		10,000		53,750
Member interest distributions								(68)
Net cash flows provided by financing activities		**119,571**		**132,515**		**56,380**		**118,245**
Net increase (decrease) in cash and cash equivalents		397		(2,362)		4,060		1,574
Cash and equivalents at beginning of period		**3,272**		**5,634**		**1,574**		
Cash and equivalents at end of period	**$**	**3,669**	**$**	**3,272**	**$**	**5,634**	**$**	**1,574**
Supplemental cash flow information								
Interest paid, net of amounts capitalized	$	16.633	$	1,763	$	4,437	$	1,883
Non-cash capital expenditures in accounts payable	$	21,360	$	(134)	$	804	$	146

See accompanying notes to consolidated financial statements.

Regency Gas Services LLC (Predecessor)
Notes to Consolidated Financial Statements

1. Organization, Business Operations and Summary of Significant Accounting Policies

Organization and Business Operations The consolidated financial statements presented herein contain the results of Regency Gas Services LLC (Predecessor and its predecessor, Regency LLC Predecessor). The financial results of the Predecessor and of Regency LLC Predecessor pre-date the formation of the registrant, Regency Energy Partners LP (the Partnership) and subsequent transactions described below.

Regency Energy Partners LP, a Delaware limited partnership, was formed on September 8, 2005 for the purpose of converting the Predecessor to a master limited partnership engaged in the business of gathering, treating, processing, transporting, and marketing natural gas and natural gas liquids (NGLs).

Initial Public Offering On September 15, 2005, a Registration Statement on Form S-1 (File No. 333-128332) was filed with the United States Securities and Exchange Commission (the SEC) relating to a proposed underwritten initial public offering (IPO) of limited partnership interests in the Partnership. On January 30, 2006, the Partnership priced 13,750,000 common units, representing a 35.3% limited partner interest in the Partnership, for the initial public offering and on January 31, 2006 the Partnership s common units began trading on the NASDAQ National Market under the symbol RGNC. On February 3, 2006, the Partnership closed its initial public offering of 13,750,000 common units at a price of $20.00 per unit. Total proceeds from the sale of the units were $275 million, before offering costs and underwriting commissions.

The assets of the Predecessor were contributed by HM Capital Partners LLC (formerly Hicks, Muse, Tate & Furst Incorporated) (HM Capital), through its wholly owned subsidiary, Regency Acquisition LP (Acquisition) in exchange for 19,103,896 subordinated units representing a 49% limited partner interest in the Partnership; 5,353,896 common units representing a 13.7% limited partner interest in the Partnership; a 2% general partner interest in the Partnership; incentive distribution rights; and the right to receive reimbursement of approximately $195.5 million of capital expenditures comprising most of the initial investment by HM Capital in Regency Gas Services LLC. Concurrent with the closing of the IPO, Regency Gas Services LLC was converted to a limited partnership and contributed to Regency Energy Partners LP.

The proceeds of the initial public offering were used to: distribute approximately $196 million to HMTF Regency LP (the Parent) for reimbursement of capital expenditures as noted above and to replenish $48 million of working capital assets which were distributed to HM Capital immediately prior to the IPO; pay $9 million to an affiliate of the Parent to terminate a management services contract; and pay $22 million of underwriting commissions, structuring fees and other offering costs. In connection with the IPO, the Predecessor incurred direct costs totaling $3.0 million as of December 31, 2005, and has included those costs in the December 31, 2005 consolidated balance sheet within Other Assets. These costs will be charged against the gross proceeds from the Partnership s IPO as a reduction to equity in the first quarter of 2006.

On March 8, 2006, the Partnership closed the sale of an additional 1,400,000 common units at a price of $20 per unit as the underwriters exercised a portion of their over allotment option. The net proceeds from the sale were used by us to redeem an equivalent number of common units held by Regency Acquisition LP for the benefit of the HM Capital Investors, reducing their partner interest to 61.1%.

Pre-IPO Organization Regency Gas Services LLC, a Delaware limited liability company, was formed April 2, 2003 and began operations on June 2, 2003. The operations include the gathering, processing, marketing, and transportation of natural gas and natural gas liquids.

On December 1, 2004, Acquisition acquired 100% of the outstanding member interests of the Company from Regency Services LLC (Seller) and became its single member owner. As the single member owner, Regency Acquisition had the right to manage the business and affairs of the Predecessor and to determine, subject to limitations imposed by credit agreements (see Note 3), the amount of any distributions payable by the Predecessor to the member. Regency Acquisition had no obligation to make any capital contribution to the Predecessor beyond its initial investment. An investment fund organized and controlled by HM Capital Partners LLC (formerly known as Hicks, Muse, Tate and Furst Incorporated) is the principal equity owner of the Parent. This acquisition is referred to as the HM Capital transaction throughout this document.

The Parent accounted for its acquisition of the Predecessor 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 the Predecessor and its subsidiaries for the periods subsequent to December 1, 2004. For periods prior to its acquisition, the Company is designated herein as the Regency LLC Predecessor, and its consolidated financial statements for periods ended before December 1, 2004 are similarly designated. The comparability of the operating results for the Regency LLC Predecessor and those of the Predecessor for subsequent periods is affected by the purchase accounting adjustments, including amortization of intangible assets. See Note 2 for further discussion of goodwill and intangible assets.

Basis of Presentation The accompanying consolidated financial statements include the assets, liabilities, results of operations and cash flows of the Predecessor and its wholly owned subsidiaries, Regency Intrastate Gas LLC, Regency Midcon Gas LLC, Regency Liquids Pipeline LLC, Regency Gas Gathering and Processing LLC, Gulf States Transmission Corporation, Regency Gas Services Waha LP, Regency NGL Marketing LP, Regency Gas Marketing LP and Regency Gas Treating LP. In May 2005, the Company disposed of the assets of Regency Gas Treating LP. These subsidiaries are Delaware limited liability companies or limited partnerships except for Gulf States Transmission Corporation, which is a Louisiana corporation. The consolidated financial statements of Regency Gas Services LLC have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). All adjustments necessary for a fair presentation of the results of operations and financial position have been included therein. All intercompany items and transactions have been eliminated in consolidation.

The Company operates and manages its business as two reportable segments: a) gathering and processing, and b) transportation. (See Note 9).

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. Actual results could differ from these estimates.

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

Restricted Cash In accordance with an escrow agreement, 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 removed from the accounts. Unless the disposition is treated as discontinued operations, any gain or loss on disposition is included in operating income. The gas required to maintain pipeline minimum pressures is capitalized and classified as property, plant, and equipment. Furthermore, interim financing costs (capitalized interest) associated with the construction of larger assets requiring ongoing efforts over a period of time are capitalized. There was no capitalized interest in 2004 or in 2003. For the year ended December 31, 2005, the Company capitalized $2.6 million of interest expense. The costs of labor, materials and overhead incurred to operate and maintain plant and equipment are included in operating expenses.

The Company 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 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 Company accounts for its asset retirement obligations in accordance with Statement of Financial Accounting Standards (SFAS) No. 143 Accounting for Asset Retirement Obligations and FIN 47 Accounting for Conditional Asset Retirement Obligations. These accounting standards require the Company 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 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 Company. While the Company 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 as of December 31, 2005 and 2004 because the settlement dates, or ranges thereof, were indeterminable and could range up to ninety-six 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 Depreciation of plant and equipment is recorded on a straight-line basis over the following estimated useful lives.

Functional Class of Property	**Useful Lives**
Gathering and Transmission	5 - 20 years
Gas Plants and Buildings	15 - 35 years
General - Land Rights of Way; Computer, Office, and Telecommunications Equipment; and Vehicles	3 - 10 years

Depreciation expense for each of the periods presented was as follows:

Period	**Depreciation Expense**	
	($ in millions)	
Inception (April 2, 2003) to December 31, 2003 (Regency LLC Predecessor)	$	4.3
January 1, 2004 to November 30, 2004 (Regency LLC Predecessor)		10.1
Acquisition date (December 1, 2004) to December 31, 2004		1.5
Year ended December 31, 2005		20.1

Intangible Assets Following the HM Capital transaction, management identified two classes of separately identifiable intangible assets, which will be amortized on a straight line basis over their useful lives. The two classes of intangible assets are (i) permits and licenses and (ii) customer contracts.

The value of the licenses and permits was determined by discounting the income associated with activities that would be lost over the period required to replace these permits. An intangible asset in the amount of $12.0 million was recognized. The Company recorded $0.8 million of amortization of this intangible asset in the year ended December 31, 2005 and $0.1 million for the month of December 2004. The estimated useful life of the asset is fifteen years.

Immediately prior to the HM Capital transaction, the Regency LLC Predecessor renegotiated a number of significant customer contracts. The value of customer contracts was determined by using a discounted cash flow model associated with the contracts. An intangible asset in the amount of $6.5 million was recognized. The Company recorded $1.1 million of amortization of this intangible asset in the year ended December 31, 2005 and $0.1 million in the month of December 2004. The estimated useful life for 67% of the contracts is 12 years, while the remaining 33% have an estimated useful life of three years.

See Note 2 for more information with respect to intangible assets.

Goodwill Following the HM Capital transaction, the Company recorded goodwill in the amount of $58.5 million. See Note 2 for more information on this transaction. In accordance with SFAS No. 142

Goodwill and Other Intangible Assets, goodwill is not subject to amortization. The Company tests for impairment to determine whether any of the asset value recorded in goodwill should be written off annually on December 31 or more frequently if events or changes in circumstances indicate that an asset might be impaired. The changes in the carrying amount of goodwill in 2004 and 2005 are as follows:

Goodwill	Gathering and Processing Segment	Transportation Segment	Regency Gas Treating LP Discontinued Operations	Total
		($ in millions)		
Balance as of January 1, 2004 (Regency LLC Predecessor)	$	$	$	$
Goodwill recorded as a result of the HM Capital transaction	23.4	34.2	0.9	58.5
Balance as of December 31, 2004	23.4	34.2	0.9	58.5
Goodwill disposed of in sale of Regency Gas Treating LP assets			(0.9)	(0.9)
Balance as of December 31, 2005	$ 23.4	$ 34.2	$	$ 57.6

Other Assets, net Other assets, net consist of debt issuance costs, which are capitalized and amortized to expense over the life of the related debt. In connection with the IPO, the Predecessor incurred direct costs totaling $3.0 million as of December 31, 2005, and has included those costs in the December 31, 2005 consolidated balance sheet within Other assets. These costs will be charged against the gross proceeds from the Partnership s IPO as a reduction to equity in the first quarter of 2006.

Gas Imbalance Accounting Pursuant to imbalance agreements for which settlement prices are not contractually established, quantities of natural gas over-delivered or under-delivered are recorded monthly as receivables or payables using the lower of cost or market for assets, and market prices for liabilities.

The Company had imbalance receivables and payables as set forth in the table below, classified in the financial statements as other current assets and other current liabilities, respectively. Within certain volumetric limits determined at the sole discretion of the creditor, these imbalances are primarily settled by deliveries of natural gas.

	Predecessor December 31, 2005	Predecessor December 31, 2004
	($ in millions)	
Imbalance Receivables	$ 1.5	$ 0.9
Imbalance Payables	$ 1.4	$ 1.0

Revenue Recognition The Company earns revenues from domestic sales of natural gas, natural gas liquids and by providing gathering and transmission services. These sales stem from gas gathering and processing and from pipeline transmission services. Revenues associated with these activities are recognized when natural gas products are delivered or at the time services are performed. The Company s gas purchase contracts are structured so that it earns margins on the resale of natural gas or NGLs reflecting the value added by gathering, processing, or transporting the products. The Company records revenue and cost of sales on the gross basis for those transactions in which it acts as principal and take title to gas purchased for resale. Where the Company acts as agent and our customers pay a fee for receiving a service such as gathering or transportation, fees are recorded in revenues and disclosed separately from sales of products.

Risk Management Activities As a result of marketing NGLs, the Company receives floating rate prices for the products that it extracts from raw natural gas. Because these sales are settled with physical deliveries, these contracts are treated as normal sales and are not marked to market.

To manage commodity price risk, the Company has implemented a risk management program under which it seeks to match sales prices of commodities (especially natural gas) with purchases under its contracts; manage its portfolio of contracts to reduce commodity price risk; optimize its portfolio by active monitoring of basis, swing, and fractionation spread exposure; and hedge a portion of its exposure to commodity prices (specifically NGLs).

To the extent that the Company purchases or commits contractually to purchase natural gas that it gathers and processes, the Company has exposure to commodity price changes in both the natural gas and NGL markets. Operationally, the Company mitigates 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, the Company optimizes the operations of its processing facilities on a daily basis, for example by rejecting ethane when recovery of ethane as an NGL is uneconomical.

As a consequence of the Company s processing contract portfolio, it derives a portion of its earnings from a long position in NGL products, resulting from the purchase of natural gas for its account or from the payment of processing charges in kind, that are exposed to commodity price fluctuations. Shortly after the HM Capital transaction, the Company implemented a policy of hedging this commodity price risk by purchasing a series of contracts relating to swaps of individual NGL products and crude oil puts. The Risk Management Committee closely monitors the Company s hedging position and its needs to supplement or modify this position. As a matter of policy, the Company does not acquire forward contracts or derivative products for the purpose of speculating on price changes.

On December 2, 2004, as required by covenants in our credit agreements, the Company entered into certain natural gas liquids swap and crude oil put option contracts.

In addition, the Company s $470 million credit facility agreement (see Note 3) exposes it to interest rate risk due to the variable nature of the interest rates stated in this credit agreement. The credit agreement requires the Company to hedge a portion of its exposure to interest rate risk. See Note 3 for more information on interest rate hedging activities.

Subsequent to the HM Capital transaction through June 30, 2005, the Company evaluated SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, to determine whether the transactions qualified for hedge accounting. During this period, these transactions were marked to market and unrealized gains and losses were recorded in revenue for the commodity contracts and in interest expense for the interest rate swap. At December 31, 2004, the net fair value of the Company s risk management activities was an asset of $9.0 million.

Effective July 1, 2005, the Company elected hedge accounting for its ethane, propane, and butane swaps, as well as for its interest rate swap. These contracts are designated as cash flow hedges under SFAS No. 133. Changes in the fair value of contracts for which hedge accounting applies are recorded in Other Comprehensive Income to the extent the hedges are effective. At December 31, 2005, the net fair value of the Company s risk management activities was a liability of $13.2 million. During the year ended December 31, 2005, realized and unrealized gains and (losses) from risk management activities of $(22.2) million has been recorded as a charge against revenue.

Hedge accounting was not elected for the Company s crude oil put options, which were used to reduce downside price exposure for natural gasoline. At the time that these crude oil put options were purchased, there was no liquid market for contracts that would exactly match the forecasted transactions hedged by the crude oil puts. These contracts have been and will continue to be marked to market with unrealized and realized gains or losses on these contracts recorded in revenue. As a liquid market developed in natural gasoline swaps, the Company began utilizing natural gasoline swaps to reduce price exposure for this commodity. These swaps have been designated as cash flow hedges under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities.

The Company continues to enter into NGL swaps, and as of December 31, 2005, has hedged its exposure to commodity price risk for a portion of its forecasted transactions in ethane, propane, butane and natural gasoline through calendar year 2007. As of December 31, 2005, $6.9 million of losses are expected to be reclassified into earnings from Other Comprehensive Income (loss) in the next twelve months. From

July 1, 2005 through December 31, 2005, the amount of ineffectiveness of the contracts designated as cash flow hedges was immaterial. Accordingly, all of the change in value during this period was recorded in other comprehensive income. See Note 11 for disclosure of subsequent event related to the Company s hedging activity.

Maintenance Costs Maintenance costs are expensed as incurred.

Benefits From inception of the Regency LLC Predecessor through May 31, 2005, the Regency LLC Predecessor and the Predecessor contracted with an independent third party to provide payroll and advisory human resource services while remaining the co-employer of all employees. On June 1, 2005, the Predecessor terminated that contract, becoming the sole employer of all its employees, and engaged a different vendor to provide payroll and supplemental human resource services. Under both arrangements, payroll and payroll related expenses are included within operating and general and administrative expenses. The Company provides a portion of medical, dental, and other healthcare benefits to employees and, commencing on June 1, 2005, a 50% matching contribution for the first 6% of employee contributions to their 401(k) accounts. The amount of matching contributions for the year ended December 31, 2005 was approximately $0.1 million. The Company has no pension obligations or other post employment benefits.

Income Taxes No provision is made in the accounts for Federal or state income taxes. The Company is not subject to these taxes because its income is taxed directly to the partners of the Parent.

Comprehensive Income (Loss) Comprehensive loss for the year ending December 31, 2005 was $22.2 million. Comprehensive income (loss) is the same as net income (loss) for all periods ending December 31, 2004 and earlier.

Earnings Per Unit Earnings per unit has not been presented as the Company is controlled through a single member owner, HM Capital. This information will be presented in periods subsequent to the IPO transaction.

Equity-Based Compensation The Company adopted SFAS 123(R) Share-Based Compensation during the first quarter of 2006 which had no impact on the financial statements. See Note 10 for further disclosures.

2. Acquisitions and Dispositions

Acquisition of Regency Gas Services LLC by the HM Capital Investors

On December 1, 2004, Regency Acquisition, a wholly owned subsidiary of the Parent, acquired 100% of the membership interest of the Predecessor (the HM Capital transaction). Equity funding for the acquisition was provided by funds managed by HM Capital and other investors, including directors and members of the Company s management (collectively, the HM Capital Investors).

The HM Capital transaction was effected pursuant to a Purchase and Sale Agreement (PSA) dated October 21, 2004 among Regency Acquisition, as the purchaser, and, among others, Regency Services LLC, the owner of the member interests in the Regency LLC Predecessor, as the seller. The aggregate purchase price was $420 million, including transaction costs of $8 million. The purchase price was funded primarily through $243 million of term loans (net of issuance costs) to the Company and $171 million of equity investments by the Parent. Pursuant to the PSA, a liability in the amount of $5.8 million was recorded at December 31, 2004 to reflect a post-closing adjustment to the purchase price primarily for working capital adjustments. The Predecessor paid this amount in February 2005.

The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at the date of acquisition.

	At December 1, 2004
	($ in millions)
Current assets	$ 66.8
Property, plant and equipment	332.0
Intangible assets, subject to amortization	18.5
Goodwill	58.5
Total assets acquired	475.8
Current liabilities	(55.8)
Net assets acquired	$ 420.0

All of the separately identified intangibles listed below were valued using a discounted cash flow methodology and are amortized using the straight-line method with no residual value.

	Permits and Licenses	Customer Contracts	Regency Gas Treating LP Permits	Total
		($ in millions)		
Useful life (in years)	15	3 - 12	n/a	
Gross carrying amount at December 1, 2004	$ 11.9	$ 6.5	$ 0.1	$ 18.5
Accumulated amortization at December 31, 2004	(0.1)	(0.1)	0.0	(0.2)
Net carrying amount at December 31, 2004	11.8	6.4	0.1	18.3
Accumulated amortization at December 31, 2005	(0.9)	(1.2)		(2.1)
Net carrying amount at December 31, 2005	$ 11.0	$ 5.3	$	$ 16.3
Amortization for the year ended December 31, 2005	$ (0.8)	$ (1.1)	$	$ (1.9)

The expected amortization of the intangible assets for each of the five succeeding years is as follows:

For the year ending December 31,	**Total**
	($ in millions)
2006	1.9
2007	1.8
2008	1.2
2009	1.2
2010	1.2

As part of the PSA, $12.5 million of the purchase price was transferred to an escrow account. The restricted cash asset and associated escrow liability are recorded on the balance sheet of Regency Acquisition (not included in these consolidated financial statements). According to the terms of the PSA and the escrow agreement, Regency Acquisition is indemnified to the extent of the amount in escrow against any losses associated with a breach by the Seller of its representations or warranties, any environmental costs or liabilities incurred as a result of circumstances on or before the closing date, and any losses incurred as a result of Gulf States Transmission Corporation s noncompliance with specified FERC regulations. A deductible of $4.0 million applies. The escrow agreement expires on May 30, 2006. As of December 31, 2005, the Parent had released approximately $6.3 million of the amount held in escrow to the Seller.

Regency Gas Treating LP

On April 1, 2004, the Regency LLC Predecessor completed the purchase of gas processing and treating assets located in Louisiana and Texas from Cardinal Gas Services LLC for $3.5 million of cash.

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The value of assumed liabilities was immaterial. Subsequent to the purchase, the assets were contributed to a new subsidiary operating as Regency Gas Treating LP. These assets consisted of Joule-Thompson and refrigeration gas processing equipment, amine gas treating equipment and contracts to provide processing and treating services. The equipment removes impurities and natural gas liquids from natural gas, resulting in the natural gas meeting standards required by transmission pipeline operators. After the acquisition, additional capacity was added. See Note 7 for additional information on this Regency LLC Predecessor related party transaction.

Soon after the acquisition by the Parent, the Company determined that these assets were not core to its operations and classified these assets as held for sale on the balance sheet at December 31, 2004. On May 2, 2005, the Company sold the assets of Regency Gas Treating LP for $6.0 million. After the allocation of $0.9 million of goodwill, the resulting gain was $0.6 million. The Company has treated Regency Gas Treating LP as a discontinued operation, the results of which are shown below:

		Predecessor	
	Predecessor Year Ended December 31, 2005	Period from Acquisition Date (December 1, 2004) to December 31, 2004	Regency LLC Predecessor Period from January 1, 2004 to November 30, 2004
		($ in millions)	
Equipment lease revenue	$ 0.3	$ 0.1	$ 0.5
Operating income (loss)	0.1		0.1
Net income (loss)	0.7		(0.1)
Gain on disposal	$ 0.6		

Waha

On March 1, 2004, the Regency LLC Predecessor completed the purchase of gathering, processing, and treating assets in west Texas from Duke Energy Field Services LP (Duke) for $67.3 million of cash and $1.0 million in assumed liabilities, including transaction costs. The facilities, known as the Waha system, consist of more than 750 miles of pipeline, 42,000 horsepower of compression, and gas processing and treating capacities of 125 MMcf/d. The assets are owned and operated by Regency Gas Services Waha, LP, a wholly owned subsidiary of the Predecessor. The purchase accounting method resulted in an allocation of the total purchase price to property, plant and equipment with no goodwill or intangible assets.

The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at the date of acquisition.

	At March 1, 2004
	($ in millions)
Current assets	$
Property, plant and equipment	67.3
Total assets acquired	67.3
Current liabilities	(1.0)

Net assets acquired	$	66.3

The following unaudited pro forma financial information has been prepared as if the acquisition of the west Texas assets had occurred at the beginning of each period presented. The pro forma amounts include certain adjustments to historical results of operations including depreciation and amortization expense (based upon the estimated fair values and useful lives of property, plant and equipment).

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Such unaudited pro forma information does not purport to be indicative of the results of operations that would have been achieved if the transactions to which the Company 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. While the Company s inception date is April 2, 2003, the pro forma results are related to only the seven months of operations ended December 31, 2003.

	Regency LLC Predecessor	
	Period from January 1, 2004 to November 30, 2004	Period from Inception (April 2, 2003) to December 31, 2003
	($ in millions)	
Revenue	$ 454.1	$ 262.6
Net Income	21.1	10.0

See Note 6 for a description of commitments and contingencies related to the Waha system.

Mid-Continent and North Louisiana

On June 2, 2003, the Regency LLC Predecessor completed an asset purchase from El Paso for the mid-continent and north Louisiana assets. These assets consist of four gas processing plants, approximately 2,400 miles of natural gas gathering and transmission pipeline, and 70,000 horsepower of compression capacity. The total purchase price was $119.5 million, including transaction closing costs. The purchase accounting method resulted in an allocation of the total purchase price to property, plant and equipment with no goodwill or intangible assets.

The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at the date of acquisition.

	At June 2, 2003
	($ in millions)
Current assets	$
Property, plant and equipment	119.5
Total assets acquired	119.5
Current liabilities	
Net assets acquired	$ 119.5

At the purchase closing date, $9.0 million of the purchase price was deposited into an escrow account as a condition of the PSA. Under the terms of the escrow agreement, certain amounts are eligible for release at various points of time following the closing date. At December 31, 2005, $5.5 million of this amount remains in escrow. See Note 6 for more information related to this escrow account.

3. Long-Term Debt

Obligations under the Company s credit facilities at December 31, 2005 and 2004 are as follows:

	Predecessor December 31, 2005	Predecessor December 31, 2004
	($ in millions)	
Term Loans	$ 308.4	$ 250.0
Revolving Loans	50.0	
Less: Current Portion		(2.0)
Long-term Debt	$ 358.4	$ 248.0
Total Facility Limit	$ 468.4	$ 290.0
Term Loans	(308.4)	(250.0)
Revolving Loans	(50.0)	
Letters of Credit	(10.7)	
Credit Available	$ 99.3	$ 40.0

During 2005, we amended our credit facility in November and in July in order to support the transition from a privately held entity to a public entity and to finance a capital expenditure program. These amendments are summarized below.

On November 30, 2005, we amended our credit facilities, increasing the first-lien term loan commitments by $50 million to $308.4 million from $258.4 million, immediately using the increased amount to convert the higher cost $50 million second-lien borrowing into a first-lien term loan. Repayments of term loan principal are now deferred until the maturity date of June 1, 2010. In addition, the interest rate applied to the resulting first-lien loan balance, as well as the rate charged for letters of credit, was reduced by 0.5%. Interest on borrowings is calculated at either an adjusted London Inter-Bank Offer Rate (LIBOR) plus an applicable margin of 2.25% per annum or a base rate plus an applicable margin of 1.25% per annum, depending on the election we make at the time of the borrowing. We will pay a commitment fee of 0.5% for the unused portion of the revolving loan commitments. For letters of credit, we will pay an aggregate rate of 2.375% per annum on the average daily outstanding balance. Payments for interest on term loans, commitment fees, and letters of credit are made at the end of each calendar quarter.

Revolving-debt commitments increased to $160 million from $150 million, and the amount available for letters of credit increased to $50 million from $30 million. Letters of credit, to the extent issued, reduce the amount available for revolving loans. The amended and restated credit agreement also includes an option to increase the term loan commitments on up to four separate occasions in an aggregate amount not to exceed $40 million. Substantially all of the Company s assets are pledged as collateral under the credit agreement. The credit facility contains financial covenants requiring us to maintain debt to adjusted EBITDA and adjusted EBITDA to interest expense ratios within certain thresholds. At December 31, 2005, the Company was in compliance with these covenants.

Upon the completion of the Partnership s IPO, further amendments took effect that enable distributions to unit holders; eliminate covenants requiring the payment of excess cash flows to reduce principal; and modify covenants related to coverage ratios, changing to less restrictive terms than those previously existing.

In accordance with EITF 96-19, Debtor s Accounting for a Modification or Exchange of Debt Instrument, the Company recorded a charge of $0.8 million in the fourth quarter of 2005 related to the extinguishment of its $50 million second-lien credit facility and amendment of the first-lien credit agreement.

In July 2005, the Company amended its credit agreement, increasing the available term loans to $309 million from $249 million, increasing the available revolving loans to $150 million from $40 million, and available letters of credit to $30 million from $20 million. Letters of credit, to the extent issued, reduced the amount available for revolving loans. Interest was charged at LIBOR or the Alternate Base Rate (ABR) (equivalent to the US prime lending rate) plus an applicable margin, which is equivalent to the rates charged prior to this amendment. In connection with the amendments of the credit agreement, the Parent contributed $15 million of additional equity, which the Company received on July 25, 2005. Upon closing of the amended credit agreements, the Company borrowed an additional $25 million of term loans. The outstanding revolver debt of $10 million was repaid, consistent with the refinancing plan, which included the above mentioned equity infusion and the additional term loan. In September 2005 the Company borrowed the remaining $35 million against the term loan commitments. The quarterly principal payment schedule was amended to require 0.25% of the original principal of any additional term loans in addition to the $0.5 million quarterly principal payments associated with the original term loans. The term loans were originally issued as $260 million of first lien debt and $50 million of second lien debt. During 2005, the Company repaid $1.7 million of these term loans. Under the agreement, term loans may not be re-borrowed once repaid. The rate paid on the second lien term notes was 3.25% greater than the rate paid on the first lien term notes. The term loans matured in two tranches, with principal repayments of $246.7 million due on June 1, 2010 and $50 million due on December 1, 2010. Commitments for the revolving credit facility were set to expire on July 26, 2010. If letters of credit were issued, fees were paid on the outstanding letter of credit balance at the rate of 2.88% or lower if the Company s credit quality improved.

Loans under the credit agreements bear interest on the outstanding balances of term debt and revolver debt at either LIBOR plus margin or at the ABR plus margin, or a combination of both. The weighted average interest rate for the two term loan facilities, including the interest rate swap settlements, was 6.75% for the year ended December 31, 2005. The effective interest rate for the revolving loans for the period was 7.57%. The weighted average effective rate for the term loans and revolving loans was 6.76% for the year ended December 31, 2005. A commitment fee on the undrawn revolver balance was charged at an annual rate of 0.5%.

Covenants within the credit agreement require the Company to maintain interest rate protection on at least one-half of its outstanding debt for a minimum of two years. In January 2005, the Company entered into an interest rate swap contract, that effectively fixed the interest rate on $125 million of the term loan borrowings at 6.47% for a period of two years. Following the July 2005 amendment of its credit facilities, the Company entered into additional interest rate swaps that effectively fix the interest rate on $200 million of LIBOR based term loans at 6.70% through March 2007 and at 7.36% through March 2009.

The following table summarizes the Company s interest rate swap contracts and reflects the 0.5% reduction of interest rates as a result of the November 2005 renegotiation of the credit agreement.

Period Covered	**Notional Amount ($ millions)**	**Fixed Pay**	**Applicable Margin As of December 31, 2005**	**Total Fixed Rate As of December 31, 2005**
April 2005 to March 2007	$ 125.0	3.715%	2.250%	5.965%
August 2005 to March 2007	75.0	4.340	2.250	6.590%
April 2007 to March 2009	200.0	4.610	2.250	6.860%

Except as summarized above, the terms of the amended credit agreements are the same as those for the $290 million credit facilities described below.

In accordance with EITF 96-19 Debtor s Accounting for a Modification or Exchange of Debt Instrument , the Company treated the amendments as an extinguishment and reissuance of debt, thereby recognizing a loss in 2005 on such transaction due to the expensing of approximately $7.7 million (consisting of $5.8 million of unamortized debt issuance costs and $1.9 million paid in July 2005 in connection with the credit facility amendment).

As of December 31, 2005 and 2004 the Company had $308.4 million and $250 million in term loans outstanding, respectively. During the year ended December 31, 2005, the Predecessor borrowed $85.5 million and repaid $35.5 million against the revolving credit facility.

On December 1, 2004, the Predecessor replaced the Regency LLC Predecessor s existing credit facility with a $290.0 million facility. The terms of the former credit facilities are described below.

$290 Million Credit Facility

At December 31, 2004, the Predecessor had two credit facilities with an aggregate capacity of $290 million. The maturity date for $240 million of this capacity was June 1, 2010, and the remaining $50 million matured on December 1, 2010. Under the agreements, the Company had a $40 million revolving credit facility and a $250 million term loan facility. Up to $20 million of letters of credit were permitted to be issued against the revolving credit facility. Under certain conditions, additional term loans were permitted in an amount not in excess of $40 million in the aggregate. As of December 31, 2004, the Predecessor had $250 million in term loans outstanding under the term loan facility. Substantially all of the Predecessor s assets were pledged as collateral under the credit agreements. Covenants within the credit agreements required the maintenance of total leverage ratios, interest coverage ratios, and annual capital expenditures within stated limits.

The credit facilities restricted payment of dividends to Regency Acquisition and the Parent, but allowed for the reimbursement of tax, legal, accounting, and filing costs incurred by those entities with certain limitations. No such distributions were made. If the Predecessor issued debt or equity securities, the agreements required a repayment of amounts borrowed equal to 100% of the net cash proceeds of an issuance of debt securities and 50% of the net cash proceeds of an issuance of equity securities. After December 31, 2005, payments of principal in addition to scheduled principal payments were required if the Company met certain excess cash flows tests.

$140.0 Million Credit Facility (terminated on December 1, 2004)

In May 2003 the Regency LLC Predecessor entered into a credit facility under which the lenders provided a $10 million revolving credit facility and a $70 million term loan facility for the principal purpose of financing the acquisition of the mid-continent and north Louisiana assets. The maturity date was December 31, 2006. The revolving credit facility had a $1.0 million sublimit for the issuance of letters of credit. The $10 million revolving credit facility was subject to a borrowing base limit. The borrowing base limit was the lesser of the sum of 80% of eligible receivables and 50% of eligible inventory or the aggregate amount of the revolving loan commitment. Substantially all of the Regency LLC Predecessor s assets were pledged as collateral under the credit agreement. Under the credit agreement, the Regency LLC Predecessor was required to maintain current ratios, total leverage ratios, fixed charge coverage ratios, tangible net worth, annual lease obligations and annual capital expenditures within stated limits.

The credit agreement restricted payment of interest and dividends on securities held by its then parent. A distribution of less than $0.1 million was paid for the reimbursement of taxes in January 2004.

The outstanding balances of term loans and revolving loans under this credit agreement bore interest at LIBOR plus margin; Base Rate, comprised of U.S. rates, plus margin; or a combination of both. The weighted average effective rate for the term loans and revolving loans was 4.89% for the eleven months ended November 30, 2004. Fees were paid on the outstanding letter of credit balance at the LIBOR Rate margin and a fronting fee of 1/8 of 1%. Commitment fees on undrawn revolver balances were charged at an annual rate of 0.50%.

On March 1, 2004, the Regency LLC Predecessor amended the credit facility discussed above. Under the amended agreement, the lenders provided a $30 million revolving credit facility and a $110 million term loan facility for the principal purpose of financing the acquisition of the Waha system. The revolving

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credit facility had a $15 million sublimit for the issuance of letters of credit. The maturity date was December 31, 2008. The terms of the amended credit facility were similar to those in the credit facility existing at December 31, 2003 with a few exceptions, including a requirement that the Regency LLC Predecessor, by June 1, 2004 enter into agreements to fix the interest cost on at least 50% of the outstanding term loans for a period of two years. Simultaneously with the March 1, 2004 amendment, the Regency LLC Predecessor expensed $1.4 million of debt issuance costs in accordance with EITF 96-19 Debtor s Accounting for a Modification or Exchange of Debt Instrument.

On December 1, 2004, in connection with the HM Capital transaction, the Regency LLC Predecessor terminated this credit facility and a $55 million notional interest rate swap contract. The outstanding debt of $101 million of term loans and $13 million of revolving loans were repaid concurrently. The remaining debt issuance costs of $1.6 million were expensed in November 2004 in connection with the December 1, 2004 transaction.

4. Fair Value of Financial Instruments

The estimated fair value of the Company s financial instruments was determined using available market information and valuation methodologies. The carrying amount of the Company s cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. The Company s restricted cash and related escrow payable approximate fair value due to the relatively short-term settlement period of the escrow payable. The Company s risk management assets and liabilities are carried at fair value. The Company s long-term debt was comprised of borrowings under credit facilities which, at December 31, 2005 and 2004 accrued interest under a floating interest rate structure. Accordingly, the carrying value approximates fair value for the amount outstanding under the credit facility.

5. Leases

The Company leases office space and certain equipment for various periods. In the normal course of business, office space leases will likely be renewed or replaced by other leases. The Company has determined that its leases are classified as 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, 2005.

For the Year Ended December 31,	Amount ($ in millions)
2006	$ 0.5
2007	0.5
2008	0.4
2009 and beyond	0.1
Total Minimum Lease Payments	$ 1.5

Total rent expense for operating leases (primarily compressor rentals), including those leases with terms of less than one year, was $1.4 million in the year ended December 31, 2005 and $1.6 million and $0.6 million in 2004 and 2003, respectively.

Regency Gas Treating (which is reported as a discontinued operation) was the lessor on certain operating leases of gas processing and gas treating equipment. These leases were not material to the Predecessor s business activities. See Note 2.

6. Commitments and Contingencies

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

Escrow Payable At December 31, 2005, $5.5 million remained in escrow pending the completion by El Paso Field Services, LP (El Paso) of environmental remediation projects pursuant to the purchase and sale agreement (El Paso PSA) related to the Company s assets in north Louisiana and in the mid-continent area. In the El Paso PSA, El Paso indemnified the Regency LLC Predecessor against losses arising from pre-closing and known environmental liabilities subject to a limit of $84 million and subject to certain deductible limits. Upon completion of a Phase II environmental study, the Regency LLC Predecessor notified El Paso of remediation obligations amounting to $1.8 million with respect to known environmental matters and $3.6 million with respect to pre-closing environmental liabilities. Upon satisfactory completion of the remediation by El Paso, the amount held in escrow will be released. These contractual rights of the Regency LLC Predecessor were continued by the Company unaffected by the HM Capital transaction and the Partnership s IPO.

Environmental Waha Phase I. A Phase I environmental study was performed on the Waha assets by an environmental consultant engaged by the Regency LLC Predecessor in connection with the pre-acquisition due diligence process in 2004. The study noted that most of the identified environmental contamination had either been remediated or was being remediated by the previous owners or operators of the properties. The study estimated potential environmental remediation costs at specific locations at $1.9 million to $3.1 million. One premise of the study was that the responsibility for remediation of the matters included in the study rests with those previous owners or operators that are engaged in remediation activities relating to those matters. No governmental agency has required that the Company undertakes these remediation efforts. The Company believes that the likelihood that it will be liable for any significant potential remediation liabilities identified in the study is remote. Separately, the Company 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 with a $10 million limit subject to certain deductibles.

TCEQ Notice of Enforcement. In November 2004, the Texas Commission on Environmental Quality, or TCEQ, sent a Notice of Enforcement, or NOE, to the Company relating to the operation of the Waha processing plant in 2001 before it was acquired by us. We settled this NOE with the TCEQ in November 2005.

Absent the alleged physical or operational changes at the Waha processing plant that precipitated the NOE, the air emissions at the plant would have been limited, based on the plant s grand fathered status under the relevant federal statutory standards, only by historical amounts until 2007. In anticipation of the expiration of that status and regardless of the outcome of the NOE, the Company submitted to the TCEQ in early February 2005 an application for a state air permit for emissions from the Waha plant predicated on the construction of an acid gas reinjection well and, after completion of the well, the reinjection of the emitted gases. That permit has been issued and requires completion of construction of the well by the end of February 2007. We estimate the capital expenditure relating to the well at $6 million.

ODEQ Notice of Violation In March 2005, the Oklahoma Department of Environmental Quality, or ODEQ, sent a notice of violation, alleging that the Company operates the Mocane processing plant in Beaver County, Oklahoma in violation of the National Emission Standard for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities, or NESHAP, and the requirements to apply for and obtain a federal operating permit (Title V permit). After seeking and obtaining advice from the Environmental Protection Agency, the ODEQ issued an order requiring the Company to apply for a Title V permit with respect to emissions from the Mocane processing plant by April 2006. No fine or penalty was imposed by the ODEQ and the Company intends to comply with the order. Resolution of this matter will not have any material adverse effect on consolidated results of operations, financial condition, or cash flows of the Company.

Regulatory Environment In August 2005, Congress enacted and the President signed the Energy Policy Act of 2005. With respect to the oil and gas industry, the new legislation focuses on the exploration and production sector, interstate pipelines, and refinery facilities. In many cases, the Act requires action by various government agencies over the near to mid-term. The Company is unable to determine what impact, if any, the Act will have on its operations and cash flows.

Employment Agreements Two members of senior management of the Company are party to employment contracts, and a third has a severance agreement. The employment agreements provide for base salaries and severance payments in certain circumstances and prohibit each person from competing with the Company or its affiliates for a certain period of time following termination. The severance agreement provides for a payment to the employee or his estate in certain circumstances. As of December 31, 2005, the maximum amount of such payment would be $0.4 million, decreased by $0.2 million for each of the next two years.

7. Related Party Transactions

Prior to the HM Capital transaction

On April 1, 2004, the Regency LLC Predecessor acquired Cardinal Gas Services LLC (now classified as a discontinued operation), a gas treating and processing business, for total cash consideration of $3.5 million. Three former executive officers of the Regency LLC Predecessor owned a portion of the equity interest in Cardinal Gas Services LLC. The acquisition was recorded using the purchase accounting method. There was no goodwill associated with this purchase. See Note 2 for more information on this transaction.

The Regency LLC Predecessor paid $0.2 million in management fees in 2004 and 2003 for corporate development and administrative services to Charlesbank Capital Partners LLC, an affiliate of the Regency LLC Predecessor prior to the HM Capital transaction.

In 2003, the Regency LLC Predecessor incurred $0.6 million of acquisition expenses on behalf of the Regency Services LLC, the Regency LLC Predecessor s Parent, which is included in advances to affiliates at December 31, 2003. These advances were settled prior to the closing of the HM Capital transaction.

The Regency LLC Predecessor had consulting contracts in place with two former directors. The contracts have been terminated and the amounts paid under these contracts in 2004 and 2003 were not material to the Regency LLC Predecessor s results of operations.

The equity interests of the members of Regency Services LLC, some of whom were formerly directors of the Regency LLC Predecessor, were sold as a result of the HM Capital transaction.

Subsequent to the HM Capital transaction

Upon the completion of the HM Capital transaction, an advisory transaction fee of $6.0 million was paid to Hicks, Muse & Co. Partners, L.P., an affiliate of HM Capital, by Regency Acquisition LLC. This amount is included in the purchase price and was allocated to the assets.

The Company paid management and financial advisory fees in the amount of $1.1 million to HM Capital in the year ended December 31, 2005, and less than $0.1 million for the month of December 2004. Concurrent with the closing of the Partnership s IPO, the Partnership paid $9.0 million to HM Capital to terminate a management services contract with a remaining tenor of 9 years and a minimum annual obligation of $1.0 million.

In connection with the amendment and restatement of the Company s credit agreement, Regency Acquisition contributed an additional $15 million of equity, which the Company received in July 2005.

8. Concentration Risk

The following table provides information about the extent of the Company s reliance on its major customers and gas suppliers. Total revenues and cost of sales from transactions with single external

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customers or suppliers amounting to 10% or more of the Company s revenues or cost of sales are disclosed below, together with the identity of the segment reporting the revenues.

		Predecessor		Regency LLC Predecessor	
Customer	Reporting Segment	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	Period from Inception (April 2, 2003) to December 31, 2003
		($ in millions)			
Alabama Gas Corporation	Transportation	$ 132.5	$ 11.1	$ 69.7	$ 22.5
Koch Hydrocarbon, LP	Gathering and Processing	*	7.1	*	27.6
Atmos Energy Marketing, LLC	Gathering and Processing	76.1	5.8	*	*
Supplier	**Reporting Segment**				
Cohort Energy Company	Transportation	$ 93.2	$ 6.8	$ 55.0	$ 28.6
KCS Energy, Inc.	Transportation	63.4	*	*	19.5
Chesapeake Energy Corporation	Transportation	75.4	3.8	*	*

* Amounts are less than 10% of total Company revenues or cost of sales for the respective periods.

Two of the customers in the table above have credit ratings of BBB or better, and the other is not rated.

The Company 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.

9. Segment Information

The Company has two reportable segments: i) gathering and processing and ii) transportation. Gathering and processing involves the collection of raw natural gas from producer wells across the Company s three operating regions, aggregated for segment reporting purposes, and transporting it to a treating plant where water and other impurities such as hydrogen sulfide and carbon dioxide are removed. Treated gas then goes through further processing to remove the natural gas liquids. The treated and processed natural gas then is transported to market, separately from the natural gas liquids. The Company s gathering and processing segment also includes its NGL marketing business. Through the NGL marketing business, the Company markets the NGLs that are produced by its processing plants for its own account and for the accounts of its customers.

The transportation segment uses pipelines to move natural gas from processing plants to interconnections with larger pipelines or to trading hubs. The Company 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 Company also purchases natural gas at the inlets to the pipeline and sells this gas at its outlets. The north Louisiana intrastate pipeline operated by this segment serves the Company s gathering and processing facilities in the same area, which create the intersegment revenues shown in the table below. The transportation segment also includes the Company s natural gas marketing business.

Management evaluates the performance of each segment and makes capital allocation decisions through the separate consideration of segment margin and operating expense. Segment margin is defined as total revenues, including service fees, less cost of gas and liquids and other costs of sales. The Company believes segment margin is an important measure because it is directly related to volumes and commodity price changes. Operating 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 the Company s operating expenses. These

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expenses are largely independent of the volume throughput but fluctuate depending on the activities performed during a specific period. The Company does not deduct operating expenses from total revenues in calculating segment margin because management separately evaluates commodity volume and price changes in segment margin. Results for each income statement period, together with amounts related to balance sheets for each segment, are shown below.

Regency Gas Services LLC (Predecessor)
Segment Information

	Gathering and Processing	Transportation	Corporate	Eliminations	Consolidated Total
			($ in millions)		
External Revenue					
For the year ended December 31, 2005	$ 488.9(1)	$ 203.7	$	$	$ 692.6
For the one month ended December 31, 2004	35.0	12.8			47.8
For the eleven months ended November 30, 2004*	317.6	114.7			432.3
For the seven months ended December 31, 2003*	113.4	73.1			186.5
Intersegment Revenue					
For the year ended December 31, 2005	$	$ 57.1	$	$ (57.1)	$
For the one month ended December 31, 2004		3.4		(3.4)	
For the eleven months ended November 30, 2004*		15.2		(15.2)	
For the seven months ended December 31, 2003*		0.6		(0.6)	
Cost of Sales					
For the year ended December 31, 2005	$ 432.7	$ 188.0	$	$	$ 620.7
For the one month ended December 31, 2004	28.8	12.2			41.0
For the eleven months ended November 30, 2004*	256.2	106.5			362.7
For the seven months ended December 31, 2003*	94.5	68.9			163.4
Segment Margin					
For the year ended December 31, 2005	$ 56.2(1)	$ 15.7	$	$	$ 71.9
For the one month ended December 31, 2004	6.2	0.6			6.8
For the eleven months ended November 30, 2004*	61.4	8.2			69.6
For the seven months ended December 31, 2003*	18.9	4.2			23.1
Operating Expenses					

For the year ended December 31, 2005	$ 19.9	$ 1.9	$	$	$ 21.8
For the one month ended December 31, 2004	1.6	0.2			1.8
For the eleven months ended November 30, 2004*	16.2	1.6			17.8
For the seven months ended December 31, 2003*	6.1	0.9			7.0
Depreciation and Amortization					
For the year ended December 31, 2005	$ 16.8	$ 4.7	$ 0.5		22.0
For the one month ended December 31, 2004	1.3	0.3			1.6
For the eleven months ended November 30, 2004*	8.1	1.4	0.6		10.1
For the seven months ended December 31, 2003*	3.2	0.9	0.2		4.3
Assets					
December 31, 2005	$ 342.6	$ 292.0	$ 19.7	$	$ 654.3
December 31, 2004	337.1	125.2	24.2		486.5
Expenditures for Long-Lived Assets					
For the year ended December 31, 2005	$ 11.1	$ 158.1	$ 0.9	$	$ 170.1
For the one month ended December 31, 2004	nm	nm	nm	nm	nm
For the eleven months ended November 30, 2004*	73.2	7.5	4.8		85.5
For the seven months ended December 31, 2003*	93.2	28.3	1.8		123.3

nm = not meaningful excludes the HM Capital Transaction

* Regency LLC Predecessor

(1) Includes $9.5 million of net unrealized losses on risk management activities and $2.0 million of non-cash put option expiration.

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

Reconciliation of Total Segment Margin to Income (Loss) from Continuing Operations

	Predecessor		Regency LLC Predecessor	
	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	Period from Inception (April 2, 2003) to December 31, 2003
	($ in millions)			
Total Segment Margin (from above)(1)	$ 71.9	$ 6.8	$ 69.6	$ 23.1
Operating expenses	21.8	1.8	17.8	7.0
General and administrative	14.4	0.6	6.6	2.7
Transaction expenses			7.0	0.7
Depreciation and amortization	22.0	1.6	10.1	4.3
OPERATING INCOME	13.7	2.8	28.1	8.4
OTHER INCOME AND DEDUCTIONS				
Interest expense, net	(17.4)	(1.3)	(5.1)	(2.4)
Loss on debt refinancing	(8.5)		(3.0)	
Other income and deductions, net	0.3		0.1	0.2
Total other income and deductions	(25.6)	(1.3)	(8.0)	(2.2)
NET INCOME (LOSS) FROM CONTINUING OPERATIONS	$ (11.9)	$ 1.5	$ 20.1	$ 6.2

(1) Includes $9.5 million of net unrealized losses on risk management activities and $2.0 million of non-cash put option expiration in 2005.

10. Equity-Based Compensation On December 12, 2005, the compensation committee of the board of directors approved a long-term incentive plan (LTIP) for the Company s employees, directors and consultants under which awards were granted following the completion of the Partnership s IPO. A total of 2,865,584 common units have been authorized for delivery under the plan. All LTIP awards are subject to a three year vesting period. For each year completed, one-third of the award will vest. The options have a maximum contractual term, expiring ten years after the grant date.

The initial grant included a total of 262,500 restricted common units and 599,300 common unit options with grant-date fair values of $20 per unit and $1.15 per option. In the aggregate, these awards represent 861,800 potential common units. The options were valued with the Black-Scholes Option Pricing Model assuming 15% volatility in the unit price, a ten year term, a strike price equal to the IPO price of $20 per unit, a distribution yield rate of 7% and an average exercise of the options of four years after vesting is complete. The assumption that employees will, on average, exercise their options four years from the vesting date is based on the average of the mid-points from vesting to expiration of the options.

Subsequent to the initial grant, the Company awarded 100,000 restricted common units and 58,000 common unit options. The awards were issued at weighted average grant date fair values of $20.51 per restricted common unit and $1.20 per unit option. In aggregate, these awards represent 158,000 potential common units. The terms of the awards and the valuation assumptions are identical to those in the initial grant, adjusted for the differences in the unit prices and grant dates.

The Partnership will make distributions to non-vested restricted common units on a 1:1 ratio with the per unit distributions paid to common units. Upon the vesting of the restricted common units and the exercise of the common unit options, the Company intends to settle these obligations with common units. Accordingly, the Partnership expects to recognize an aggregate of $7.7 million of compensation expense

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related to the grants under LTIP, or $2.6 million for each of the three years of the vesting period for such grants. The Company has adopted SFAS 123(R) Share-Based Payment for accounting for its LTIP. The timing of the inception of the LTIP allowed the Company to adopt SFAS 123(R) in the first quarter of 2006 with no associated accounting changes.

Senior members of management and outside directors who held Class B or Class D units of HMTF Regency, L.P. entered into exchange agreements in connection with the consummation of the Partnership s IPO whereby they exchanged their Class B or Class D units for common and subordinated units in Regency Energy Partners LP and an interest in Regency GP LLC. The Company has evaluated the impact of the exchange agreements and will not record a material amount of compensation expense related to this exchange.

11. Subsequent Event

On March 24, 2006, the Partnership executed swap contracts to hedge approximately 50% of its exposure to price volatility for ethane, propane, butane and natural gasoline for the calendar year 2008. The contracts have been designated as cash flow hedges and due to their matched terms are expected to have no ineffectiveness. Accordingly, changes in the fair value of these contracts will be recorded in other comprehensive income.

12. Quarterly Financial Data (Unaudited)

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss)
		($ in thousands)	
2005:			
March 31	$ 106,612	$ (12,064)	$ (15,141)
June 30	137,350	10,757	6,482
September 30	190,604	8,197	(3,901)
December 31	258,037	6,728	1,336
2004:			
March 31	$ 94,991	$ 5,987	$ 3,450
June 30	115,700	6,949	5,640
September 30	128,415	13,099	11,452
Month ended December 31	47,841	2,785	1,464
Two months ended November 30 (Regency LLC Predecessor)	93,215	2,035	(526)

Earnings per unit information has not been presented as the Company is controlled through a single member owner, HM Capital. The Predecessor adopted hedge accounting for its commodity and interest rate swap contracts at the beginning of the quarter ended September 30, 2005. In accordance with SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities, the changes in the value of these contracts were recorded in other comprehensive income for those periods where hedge accounting was elected.