Regency Energy Partners LP
Form 10-Q
November 10, 2008

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2008

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: 000-51757

REGENCY ENERGY PARTNERS LP
(Exact name of registrant as specified in its charter)

DELAWARE	16-1731691
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
2001 BRYAN STREET, SUITE 3700 DALLAS, TX	75201
(Address of principal executive offices)	(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.)

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.þ Yes o No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer, accelerated filer, and small reporting company” in Rule 12b-2 of the Exchange Act. (Check one):

þ Large accelerated filer o Accelerated filer

o Non-accelerated filer (Do not check if a smaller reporting company) o Smaller reporting company

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

The issuer had 54,815,951 common units, 7,276,506 Class D common units, and 19,103,896 subordinated units outstanding as of October 31, 2008.

Introductory Statement

References in this report to the "Partnership," "we," "our," "us" and similar terms, when used in a historical context, refer to Regency Energy Partners LP, or the Partnership, and to Regency Gas Services LLC, all the outstanding member interests of which were contributed to the Partnership on February 3, 2006, and its subsidiaries. When used in the present tense or prospectively, these terms refer to the Partnership and its subsidiaries. We use the following definitions in this quarterly report on Form 10-Q:

Name	Definition or Description
ASC	ASC Hugoton LLC, an affiliate of GECC
Bbls/d	Barrels per day
Bcf	One billion cubic feet
Bcf/d	One billion cubic feet per day
BTU	A unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit
CDM	CDM Resource Management LLC
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
DOT	U.S. Department of Transportation
EIA	Energy Information Administration
EnergyOne	FrontStreet EnergyOne LLC
El Paso	El Paso Field Services, LP
EPA	Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FrontStreet	FrontStreet Hugoton LLC
GAAP	Accounting principles generally accepted in the United States
GE	General Electric Company
GE EFS	General Electric Energy Financial Services, a unit of GECC, combined with Regency GP Acquirer LP and Regency LP Acquirer LP
GECC	General Electric Capital Corporation, an indirect wholly owned subsidiary of GE
General Partner	Regency GP LP, the general partner of the Partnership, or Regency GP LLC, the general partner of Regency GP LP, which effectively manages the business and affairs of the Partnership
GSTC	Gulf States Transmission Corporation
HLPSA	Hazardous Liquid Pipeline Safety Act
IRS	Internal Revenue Service
LIBOR	London Interbank Offered Rate
MMbtu	One million BTUs
MMbtu/d	One million BTUs per day
MMcf	One million cubic feet
MMcf/d	One million cubic feet per day
MQD	Minimum Quarterly Distribution
Nexus	Nexus Gas Holdings, LLC
NOE	Notice of Enforcement
NGA	Natural Gas Act of 1938
NGLs	Natural gas liquids
NGPA	Natural Gas Policy Act of 1978
NGPSA	Natural Gas Pipeline Safety Act of 1968, as amended
NPDES	National Pollutant Discharge Elimination System
Nasdaq	Nasdaq Stock Market, LLC
NYMEX	New York Mercantile Exchange
OSHA	Occupational Safety and Health Act
Partnership	Regency Energy Partners LP
	Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP

Partnership Agreement

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Pueblo	Pueblo Midstream Gas Corporation
RCRA	Resource Conservation and Recovery Act
RGS	Regency Gas Services LLC
RIGS	Regency Intrastate Gas LLC
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standard
Sonat	Southern Natural Gas Company
TCEQ	Texas Commission on Environmental Quality
Tcf	One trillion cubic feet
Tcf/d	One trillion cubic feet per day
TRRC	Texas Railroad Commission

Cautionary Statement about Forward-Looking Statements

Certain matters discussed in this report include "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Statements using words such as "anticipate," "believe," "intend," "project," "plan," "expect," "continue," "estimate," "goal," "forecast," "may" or similar expr identify forward-looking statements. Although we believe our forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, we can not give assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions including without limitation the following:

- changes in laws and regulations impacting the midstream and compression sectors of the natural gas industry;
- declines in the credit markets and the availability of credit for us as well as for producers connected to our systems and our customers;
- the level of creditworthiness of our counterparties and customers;
- our ability to access the debt and equity markets;
- our use of derivative financial instruments to hedge commodity and interest rate risks;
- the amount of collateral required to be posted from time to time in our transactions;
- changes in commodity prices, interest rates, demand for our services;
- weather and other natural phenomena;
- industry changes including the impact of consolidations and changes in competition;
- our ability to obtain required approvals for construction or modernization of our facilities and the timing of operations of such facilities; and
- the effect of accounting pronouncements issued periodically by accounting standard setting boards.

If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may differ materially from those anticipated, estimated, projected or expected. Many of the factors that will determine these results are beyond our ability to control or predict. For additional discussion of risks, uncertainties and assumptions, see "Risk Factors" included in Part I, Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2007 and in Part II, Item 1A of our quarterly reports on Form 10-Q.

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

Part 1-Financial Information
Item 1. Financial Statements

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

	September 30, 2008 (Unaudited)	December 31, 2007*
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 14,819	$ 32,971
Restricted cash	10,042	6,029
Trade accounts receivable, net of allowance of $870 in 2008 and $61 in 2007	35,608	16,487
Accrued revenues	131,058	117,622
Related party receivables	1,508	61
Assets from risk management activities	9,521	-
Other current assets	6,685	6,723
Total current assets	209,241	179,893
Property, plant and equipment		
Gathering and transmission systems	616,187	635,206
Compression equipment	754,710	145,555
Gas plants and buildings	142,690	134,300
Other property, plant and equipment	154,810	105,399
Construction-in-progress	127,687	33,552
Total property, plant and equipment	1,796,084	1,054,012
Less accumulated depreciation	(203,317)	(140,903)
Property, plant and equipment, net	1,592,767	913,109
Other Assets:		
Intangible assets, net of accumulated amortization of $18,866 in 2008 and $8,929 in 2007	205,447	77,804
Long-term assets from risk management activities	14,424	-
Goodwill	265,990	94,075
Other, net of accumulated amortization of debt issuance costs of $4,601 in 2008 and $2,488 in 2007	16,974	13,529
Total other assets	502,835	185,408
TOTAL ASSETS	$ 2,304,843	$ 1,278,410
LIABILITIES & PARTNERS' CAPITAL		
Current Liabilities:		
Trade accounts payable	$ 66,107	$ 48,904
Accrued cost of gas and liquids	104,648	96,026
Related party payables	-	50
Escrow payable	10,042	6,029
Liabilities from risk management activities	24,027	37,852
Other current liabilities	31,845	9,397

Total current liabilities		236,669		198,258
Long-term liabilities from risk management activities		6,170		15,073
Other long-term liabilities		15,591		15,393
Long-term debt		1,006,500		481,500
Minority interest in consolidated subsidiary		12,389		4,893
Commitments and contingencies				
Partners' Capital:				
Common units (55,586,453 and 41,283,079 units authorized; 54,813,451 and 40,514,895 units issued and outstanding at September 30, 2008 and December 31, 2007)		766,658		490,351
Class D common units (7,276,506 units authorized, issued and outstanding at September 30, 2008)		224,902		-
Class E common units (4,701,034 units authorized, issued and outstanding at December 31, 2007)		-		92,962
Subordinated units (19,103,896 units authorized, issued and outstanding at September 30, 2008 and December 31, 2007)		(609)		7,019
General partner interest		29,232		11,286
Accumulated other comprehensive income (loss)		7,341		(38,325)
Total partners' capital		1,027,524		563,293
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$	2,304,843	$	1,278,410

See accompanying notes to condensed consolidated financial statements

* Recast to reflect an acquisition accounted for in a manner similar to a pooling of interests.

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

	Three Months Ended		Nine Months Ended	
	September 30, 2008	September 30, 2007 *	September 30, 2008	September 30, 2007 *
REVENUES				
Gas sales	$ 323,411	$ 175,107	$ 922,872	$ 538,360
NGL sales	120,538	90,605	355,558	237,382
Gathering, transportation and other fees, including related party amounts of $939, $541, $2,865 and $1,325	74,267	30,478	206,429	69,553
Net realized and unrealized gain (loss) from risk management activities	6,817	(8,088)	(39,600)	(10,798)
Other	22,142	7,722	53,856	20,584
Total revenues	547,175	295,824	1,499,115	855,081
OPERATING COSTS AND EXPENSES				
Cost of sales, including related party amounts of $632, $656, $1,878 and $13,829	408,165	234,946	1,168,441	696,644
Operation and maintenance	33,688	18,134	95,049	41,031
General and administrative	13,976	6,983	38,784	32,928
(Gain) loss on asset sales, net	(34)	(777)	434	1,562
Management services termination fee	-	-	3,888	-
Transaction expenses	2	-	536	-
Depreciation and amortization	26,422	14,993	74,638	39,123
Total operating costs and expenses	482,219	274,279	1,381,770	811,288
OPERATING INCOME	64,956	21,545	117,345	43,793
Interest expense, net	(16,072)	(10,894)	(48,261)	(41,740)
Loss on debt refinancing	-	(21,200)	-	(21,200)
Other income and deductions, net	118	713	450	951
Minority interest	(162)	(156)	(165)	(130)
INCOME (LOSS) BEFORE INCOME TAXES	48,840	(9,992)	69,369	(18,326)
Income tax expense (benefit)	(67)	(160)	142	65
NET INCOME (LOSS)	$ 48,907	$ (9,832)	$ 69,227	$ (18,391)
General partner's interest in current period net income (loss), including IDR	7,592	(256)	8,661	(433)
Beneficial conversion feature for Class C common units	-	-	-	1,385
Beneficial conversion feature for Class D common units	1,887	-	5,312	-
Limited partners' interest in net income (loss)	$ 39,428	$ (9,576)	$ 55,254	$ (19,343)
Basic and Diluted earnings per unit:				

Amount allocated to common and subordinated units	$ 39,428	$ (12,540)	$ 55,254	$ (22,621)
Weighted average number of common and subordinated units outstanding	70,043,532	55,269,457	63,838,515	48,306,666
Basic income (loss) per common and subordinated unit	$ 0.56	$ (0.23)	$ 0.87	$ (0.47)
Diluted income (loss) per common and subordinated unit	$ 0.53	$ (0.23)	$ 0.85	$ (0.47)
Distributions per unit	$ 0.445	$ 0.38	$ 1.265	$ 1.13
Amount allocated to Class B common units	$ -	$ -	$ -	$ -
Weighted average number of Class B common units outstanding	-	-	-	871,673
Income per Class B common unit	$ -	$ -	$ -	$ -
Distributions per unit	$ -	$ -	$ -	$ -
Amount allocated to Class C common units	$ -	$ -	$ -	$ 1,385
Total number of Class C common units outstanding	-	-	-	2,857,143
Income per Class C common unit due to beneficial conversion feature	$ -	$ -	$ -	$ 0.48
Distributions per unit	$ -	$ -	$ -	$ -
Amount allocated to Class D common units	$ 1,887	$ -	$ 5,312	$ -
Total number of Class D common units outstanding	7,276,506	-	7,276,506	-
Income per Class D common unit due to beneficial conversion feature	$ 0.26	$ -	$ 0.73	$ -
Distributions per unit	$ -	$ -	$ -	$ -
Amount allocated to Class E common units	$ -	$ 2,964	$ -	$ 3,278
Total number of Class E common units outstanding	-	4,701,034	4,701,034	4,701,034
Income per Class E common unit	$ -	$ 0.63	$ -	$ 0.70
Distributions per unit	$ -	$ 2.06	$ -	$ 2.32

See accompanying notes to condensed consolidated financial statements

* Recast to reflect an acquisition accounted for in a manner similar to a pooling of interests.

Regency Energy Partners LP
Condensed Consolidated Statements of Comprehensive Income (Loss)
Unaudited
(in thousands)

	Three Months Ended		Nine Months Ended	
	September 30, 2008	September 30, 2007 *	September 30, 2008	September 30, 2007 *
Net income (loss)	$ 48,907	$ (9,832)	$ 69,227	$ (18,391)
Net hedging amounts reclassified to earnings	14,787	4,641	40,389	7,457
Net change in fair value of cash flow hedges	55,182	(11,694)	5,277	(33,072)
Comprehensive income (loss)	$ 118,876	$ (16,885)	$ 114,893	$ (44,006)

See accompanying notes to condensed consolidated financial statements

* Recast to reflect an acquisition accounted for in a manner similar to a pooling of interests.

Regency Energy Partners LP
Condensed Consolidated Statements of Cash Flows
Unaudited
(in thousands)

	Nine Months Ended	
	September 30, 2008	September 30, 2007 *
OPERATING ACTIVITIES		
Net income (loss)	$ 69,227	$ (18,391)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:		
Depreciation and amortization, including debt issuance cost amortization	76,751	40,627
Write-off of debt issuance costs	-	5,078
Equity income and minority interest in earnings	165	130
Risk management portfolio valuation changes	(1,007)	1,634
Loss on asset sales	434	1,562
Unit based compensation expenses	3,087	14,790
Gain on insurance settlements	(3,282)	-
Cash flow changes in current assets and liabilities:		
Trade accounts receivable and accrued revenues	(11,084)	(14,857)
Other current assets	38	251
Trade accounts payable, accrued cost of gas and liquids, and related party payables	(11,125)	15,171
Other current liabilities	22,448	4,132
Other assets and liabilities	3,628	(946)
Net cash flows provided by operating activities	149,280	49,181
INVESTING ACTIVITIES		
Capital expenditures	(243,660)	(108,983)
Acquisitions	(577,344)	(34,844)
Acquisition of investment in unconsolidated subsidiary, net of $100 cash	-	(5,000)
Proceeds from asset sales	696	11,723
Proceeds from insurance settlements	3,282	-
Net cash flows used in investing activities	(817,026)	(137,104)
FINANCING ACTIVITIES		
Net borrowings under revolving credit facilities	525,000	33,300
Repayments under credit facilities	-	(50,000)
Repayments of senior notes, net of debt issuance costs	-	(192,500)
Partner contributions	11,753	7,735
Partner distributions	(86,448)	(56,208)
Proceeds from option exercises	2,700	-
Debt issuance costs	(2,925)	(1,164)
FrontStreet distributions	-	(4,800)
FrontStreet contributions	-	10,895
Proceeds from equity issuances, net of issuance costs	199,514	353,446

Net cash flows provided by financing activities		649,594		100,704
Net increase (decrease) in cash and cash equivalents		(18,152)		12,781
Cash and cash equivalents at beginning of period		32,971		11,932
Cash and cash equivalents at end of period	$	14,819	$	24,713
Supplemental cash flow information:				
Interest paid, net of amounts capitalized	$	37,634	$	51,324
Income taxes paid		596		-
Non-cash capital expenditures in accounts payable		24,871		3,359
Non-cash capital expenditures for consolidation of investment in previously unconsolidated subsidiary		-		5,650
Non-cash capital expenditure upon entering into a capital lease obligation		-		3,000
Issuance of common units for an acquisition		219,590		19,724
Release of escrow payable from restricted cash		4,487		-

See accompanying notes to condensed consolidated financial statements

* Recast to reflect an acquisition accounted for in a manner similar to a pooling of interests.

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Regency Energy Partners LP
Condensed Consolidated Statements of Partners' Capital
Unaudited
(in thousands except unit data)

	Units									
	Common	Class D	Class E	Subordinated	Common Unitholders	Class D Unitholders	Class E Unitholders	Subordinated Unitholders	General Partner Interest	Accu C Comp In (I
Balance - December 31, 2007 *	40,514,895	-	4,701,034	19,103,896	$ 490,351	$ -	$ 92,962	$ 7,019	$ 11,286	$ (3
Issuance of Class D common units	-	7,276,506	-	-	-	219,590	-	-	-	
Issuance of restricted common units and option exercises, net of forfeitures	576,613	-	-	-	2,700	-	-	-	-	
Issuance of common units	9,020,909	-	-	-	199,514	-	-	-	-	
Working capital adjustment on FrontStreet	-	-	-	-	-	-	(858)	-	-	
Conversion of Class E common units	4,701,034	-	(4,701,034)	-	92,104	-	(92,104)	-	-	
Unit based compensation expenses	-	-	-	-	3,087	-	-	-	-	
General partner contributions	-	-	-	-	-	-	-	-	11,753	
Partner distributions	-	-	-	-	(59,814)	-	-	(24,166)	(2,468)	
Net income	-	-	-	-	38,716	5,312	-	16,538	8,661	
Net hedging amounts reclassified to earnings	-	-	-	-	-	-	-	-	-	4
Net change in fair value of cash flow	-	-	-	-	-	-	-	-	-	

hedges										
Balance - September 30, 2008	54,813,451	7,276,506	-	19,103,896	$ 766,658	$ 224,902	$ -	$ (609)	$ 29,232	$

See accompanying notes to condensed consolidated financial statements

*Recast to reflect an acquisition accounted for in a manner similar to a pooling of interests.

Regency Energy Partners LP
Notes to Unaudited Condensed Consolidated Financial Statements

1. Organization and Summary of Significant Accounting Policies
Organization and Basis of Presentation. The unaudited condensed consolidated financial statements presented herein contain the results of Regency Energy Partners LP, a Delaware limited partnership, and its wholly owned and consolidated subsidiaries. The Partnership and its subsidiaries are engaged in the business of gathering, processing, contract compression, marketing, and transporting natural gas and NGLs. The Partnership operates and manages its business as three reportable segments: (a) gathering and processing, (b) transportation, and (c) contract compression.

On January 7, 2008, the Partnership acquired all of the outstanding equity and minority interest (the "FrontStreet Acquisition") of FrontStreet from ASC and EnergyOne. FrontStreet owns a gas gathering system located in Kansas and Oklahoma, which is operated by a third party.

The total purchase price consisted of (a) 4,701,034 Class E common units of the Partnership issued to ASC in exchange for its 95 percent interest and (b) $11,752,000 in cash to EnergyOne in exchange for its five percent minority interest and the termination of a management services contract valued at $3,888,000. The Partnership financed the cash portion of the purchase price with borrowings under its revolving credit facility.

In connection with the FrontStreet Acquisition, the Partnership amended the Partnership Agreement to create the Class E common units. The Class E common units have the same terms and conditions as the Partnership's common units, except that the Class E common units are not entitled to participate in earnings or distributions of operating surplus by the Partnership. The Class E common units were issued in a private placement conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933 as afforded by Section 4(2) thereof. The Class E common units converted into common units on a one-for-one basis on May 5, 2008.

Because the acquisition of ASC's 95 percent interest is a transaction between commonly controlled entities (i.e., the buyer and the seller were each affiliates of GECC), the Partnership accounted for this portion of the acquisition in a manner similar to the pooling of interest method. Under this method of accounting, the financial statements reflected historical balance sheet data for both the Partnership and FrontStreet instead of reflecting the fair market value of FrontStreet's assets and liabilities. Further, certain transaction costs that would otherwise be capitalized were expensed. Common control between the Partnership and FrontStreet began on June 18, 2007. Accordingly, the statement of operations for the three and nine months ending September 30, 2007 have been recast to include the results of FrontStreet from June 18, 2007 through the end of the period.

Conversely, the acquisition of the five percent minority interest is a transaction between independent parties, for which the Partnership applied the purchase method of accounting. The final purchase price allocation, which management expects to be completed before year end, may differ from the estimates.

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

	At June 18, 2007 (in thousands)
Current assets	$ 8,840

Property, plant and equipment		91,556
Total assets acquired		100,396
Current liabilities		(12,556)
Net book value of assets acquired	$	87,840

The unaudited financial information as of, and for the three and nine months ended, September 30, 2008 has been prepared on the same basis as the audited consolidated financial statements included in the Partnership's Annual Report on Form 10-K, as amended by Form 8-K filed on May 9, 2008, for the year ended December 31, 2007. In the opinion of the Partnership's management, such financial information reflects all adjustments necessary for a fair presentation of the financial position and the results of operations for such interim periods in accordance with GAAP. All intercompany items and transactions have been eliminated in consolidation. Certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with GAAP have been omitted pursuant to the rules and regulations of the SEC.

Use of Estimates. The unaudited condensed consolidated financial statements have been prepared in conformity with GAAP and, of necessity, include the use of estimates and assumptions by management. Actual results could differ from these estimates.

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

	Permits and Licenses	Customer Contracts	Trade Names	Total
		(in thousands)		
Balance at December 31,2007	$ 9,368	$ 68,436	$ -	$ 77,804
Additions	-	102,480	35,100	137,580
Disposals	-	-	-	-
Amortization	(590)	(7,680)	(1,667)	(9,937)
Balance at September 30, 2008	$ 8,778	$ 163,236	$ 33,433	$ 205,447

The weighted average amortization period for permits and licenses, customer contracts, and trade names are 15, 20, and 15 years, respectively. The expected amortization of the intangible assets for each of the five succeeding years is as follows.

Year ending December 31,	Total (in thousands)
2008 (remaining)	$ 3,456
2009	12,358
2010	12,264
2011	10,950
2012	10,713

Recently Issued Accounting Standards. In January 2007, the FASB issued SFAS No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities, Including an Amendment of FASB Statement No. 115” (“SFAS No. 159”), which permits entities to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis. The adoption of SFAS No. 159 in 2008 had no impact on the Partnership’s financial position, results of operations or cash flows, as the Partnership has elected to continue valuing its outstanding senior notes at historical cost.

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

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

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

In March 2008, the FASB issued EITF 07-4, “Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships” (“EITF No. 07-4”). EITF No. 07-4 defines how to allocate net income among the various classes of equity, including incentive distribution rights, narrowing the number of currently acceptable methods. The standard becomes effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application is not permitted, and EITF No. 07-4 must be applied retrospectively for all financial statements presented. This new standard is not expected to have a material impact on the Partnership’s financial position, results of operations or cash flows.

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

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

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

2. Income (Loss) per Limited Partner Unit

In connection with the CDM acquisition discussed below, the Partnership issued 7,276,506 Class D common units. At the commitment date, the sales price of $30.18 per unit represented a $1.10 discount from the fair value of the Partnership's common units. Under EITF No. 98-5, "Accounting for Convertible Securities with Beneficial Conversion Features or Contingently Adjustable Conversion Ratios," the discount represented a beneficial conversion feature that is treated as a non-cash distribution for purposes of calculating earnings per unit. The beneficial conversion feature is reflected in income per unit using the effective yield method over the period the Class D common units are outstanding, as indicated on the statements of operations in the line item entitled "beneficial conversion feature for Class D common units."

The following table provides a reconciliation of the numerator and denominator of the basic and diluted earnings per unit computations for the three and nine months ended September 30, 2008.

	For the Three Months Ended September 30, 2008			For the Nine Months Ended September 30, 2008		
	Income (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
	(in thousands except unit and per unit data)					
Basic Earnings per Unit						
Limited partner's interest in net income	$ 39,428	70,043,532	$ 0.56	$ 55,254	63,838,515	$ 0.87
Effect of Dilutive Securities						
Common unit options	-	37,969		-	111,134	
Restricted common units	-	18,412		-	50,657	
Class D common units	1,887	7,276,506		5,312	7,276,506	
Diluted Earnings per Unit	$ 41,315	77,376,419	$ 0.53	$ 60,566	71,276,812	$ 0.85

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

	Three Months Ended		Nine Months Ended	
	September 30, 2008	September 30, 2007	September 30, 2008	September 30, 2007
Restricted common units	-	386,500	-	386,500
Common unit options	-	776,968	-	776,968

3. Acquisitions and Dispositions

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

The total purchase price paid by the Partnership for the partnership interests of CDM consisted of (a) the issuance of an aggregate of 7,276,506 Class D common units of the Partnership, which were valued at $219,590,000 and (b) an aggregate of $478,445,000 in cash, $316,500,000 of which was used to retire CDM's debt obligations. Of the Class D common units issued, 4,197,303 Class D common units were deposited with an escrow agent pursuant to an escrow agreement. Such common units constitute security to the Partnership for a period of one year after the closing with respect to any obligations under the Merger Agreement, including obligations for breaches of representation, warranties and covenants.

In connection with the CDM merger, the Partnership amended the Partnership Agreement to create the Class D common units. The Class D common units have the same terms and conditions as the Partnership's common units, except that the Class D common units are not entitled to participate in distributions of operating surplus by the Partnership. The Class D common units automatically convert into common units on a one-for-one basis on the close of business on the first business day after the record date for the quarterly distribution on the common units for the quarter ending December 31, 2008. The Class D common units were issued in a private placement conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933 under Section 4(2) thereof.

The total purchase price of $699,702,000, including direct transaction costs, was allocated preliminarily as follows.

	At January 15, 2008 (in thousands)
Current assets	$ 19,463
Other assets	4,547
Gas plants and buildings	1,528
Gathering and transmission systems	421,160
Other property, plant and equipment	2,728
Construction-in-progress	36,239
Identifiable intangible assets	80,480
Goodwill	164,668
Assets acquired	730,813
Current liabilities	(31,054)
Other liabilities	(57)
Net assets acquired	$ 699,702

The final purchase price allocation, which management expects to be completed before year end, may differ from the above estimates.

Nexus Gas Holdings, LLC. On March 25, 2008, the Partnership acquired Nexus ("Nexus Acquisition") by merger for $88,486,000 in cash, including customary closing adjustments. Nexus Gas Partners LLC, the sole member of Nexus prior to the merger ("Nexus Member"), deposited $8,500,000 in an escrow account as security to the Partnership for a period of one year against indemnification obligations and any purchase price adjustment. The Partnership funded the Nexus Acquisition through borrowings under its revolving credit facility.

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

The total purchase price of $88,486,000 was allocated preliminarily as follows.

		At March 25, 2008 (in thousands)
Current assets	$	3,457
Buildings		13
Gathering and transmission systems		16,960
Other property, plant and equipment		4,440
Identifiable intangible assets		57,100
Goodwill		7,187
Assets acquired		89,157
Current liabilities		(671)
Net assets acquired	$	88,486

The final purchase price allocation, which management expects to be completed before year end, may differ from the above estimates.

The following unaudited pro forma financial information has been prepared as if the acquisitions of FrontStreet, CDM and Nexus had occurred as of the beginning of the periods presented. Results for the nine months ended September 30, 2007 include the Partnership's acquisition of Pueblo because that acquisition occurred in April 2007. Such unaudited pro forma financial information does not purport to be indicative of the results of operations that would have been achieved if the transactions to which the Partnership is giving pro forma effect actually occurred on the date referred to above or the results of operations that may be expected in the future.

	Pro Forma Results for the							
	Three Months Ended				Nine Months Ended			
	September 30, 2008		September 30, 2007		September 30, 2008		September 30, 2007	
	(in thousands except unit and per unit data)							
Revenue	$	547,175	$	322,915	$	1,506,322	$	953,445
Net income (loss)	$	48,907	$	(7,917)	$	71,041	$	(9,075)
Less:								
General partner's interest in current period net income (loss), including IDR		7,592		(217)		8,697		(246)
Beneficial conversion feature for Class C common units		-		-		-		1,385
Beneficial conversion feature for Class D common units		1,887		-		5,312		-
Limited partners' interest in net income (loss)	$	39,428	$	(7,700)	$	57,032	$	(10,214)
Basic and Diluted earnings per unit:								
Amount allocated to common and subordinated units	$	39,428	$	(10,664)	$	57,032	$	(13,492)
Weighted average number of common and subordinated units outstanding		70,043,532		55,269,457		63,838,515		48,306,666
Basic income (loss) per common and subordinated unit	$	0.56	$	(0.19)	$	0.89	$	(0.28)
Diluted income (loss) per common and subordinated unit	$	0.53	$	(0.19)	$	0.87	$	(0.28)
Distributions per unit	$	0.445	$	0.38	$	1.265	$	1.13

Amount allocated to Class B common units	$	-	$	-	$	-	$	-
Weighted average number of Class B common units outstanding		-		-		-		871,673
Income per Class B common unit	$	-	$	-	$	-	$	-
Distributions per unit	$	-	$	-	$	-	$	-
Amount allocated to Class C common units	$	-	$	-	$	-	$	1,385
Total number of Class C common units outstanding		-		-		-		2,857,143
Income per Class C common unit due to beneficial conversion feature	$	-	$	-	$	-	$	0.48
Distributions per unit	$	-	$	-	$	-	$	-
Amount allocated to Class D common units	$	1,887	$	-	$	5,312	$	-
Total number of Class D common units outstanding		7,276,506		-		7,276,506		-
Income per Class D common unit due to beneficial conversion feature	$	0.26	$	-	$	0.73	$	-
Distributions per unit	$	-	$	-			$	-
Amount allocated to Class E common units	$	-	$	2,964	$	-	$	3,278
Total number of Class E common units outstanding		-		4,701,034		4,701,034		4,701,034
Income per Class E common unit	$	-	$	0.63	$	-	$	0.70
Distributions per unit	$	-	$	2.06			$	2.32

4. Risk Management Activities

The net fair value of the Partnership's risk management activities constituted a net liability of $6,252,000 at September 30, 2008. The Partnership expects to reclassify $963,000 of net hedging gains to revenues or interest expense from accumulated other comprehensive income (loss) in the next twelve months. During the three and nine months ended September 30, 2008, the Partnership recorded $19,917,000 and $2,090,000 of mark-to-market gain and loss, respectively, for certain commodity hedges that do not qualify for hedge accounting. In the three and nine months ended September 30, 2008, the Partnership recognized $1,512,000 and $1,998,000 of ineffectiveness gains, respectively. In the three and nine months ended September 30, 2008, the Partnership recorded in net realized and unrealized gain (loss) from risk management activities a $162,000 and $1,110,000, respectively, of gains associated with its credit risk assessment in accordance with SFAS No. 157, "Fair Value Measurements" ("SFAS No. 157").

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

Effective June 19, 2007, the Partnership elected to account for all outstanding commodity hedging instruments on a mark-to-market basis except for the portion pursuant to which all NGL products for a particular year were hedged and the hedging relationship was, for accounting purposes, effective. The Partnership has a total of six hedging programs for a three-year period including 2008 through 2010 NGL hedging programs and West Texas Intermediate crude oil hedging programs to hedge condensate for 2008 through 2010.

In March 2008, the Partnership entered offsetting trades against its existing 2009 portfolio of mark-to-market hedges, which it believes will substantially reduce the volatility of its 2009 hedges. This group of trades, along with the pre-existing 2009 portfolio, will continue to be accounted for on a mark-to-market basis. Simultaneously, the Partnership executed additional 2009 NGL swaps which were designated under SFAS No. 133 as cash flow hedges. In May 2008, the Partnership entered into commodity swaps to hedge a portion of its 2010 NGL commodity risk, except for ethane, which are accounted for using mark-to-market accounting.

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

On February 29, 2008, the Partnership entered into two-year interest rate swaps related to $300,000,000 of borrowings under its revolving credit facility, effectively locking the base rate for these borrowings at 2.4 percent, plus the applicable margin (2.0 percent as of September 30, 2008) through March 5, 2010. These interest rate swaps were designated as cash flow hedges in March 2008.

5. Long-Term Debt

Long-term debt obligations of the Partnership are as follows:

	September 30, 2008	December 31, 2007
	(in thousands)	
Senior notes	$ 357,500	$ 357,500
Revolving loans	649,000	124,000

Total		1,006,500		481,500
Less: current portion		-		-
Long-term debt	$	1,006,500	$	481,500
Availability under revolving credit facility:				
Total credit facility limit	$	900,000	$	500,000
Revolving loans		(649,000)		(124,000)
Letters of credit		(16,257)		(27,263)
Total available	$	234,743	$	348,737

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RGS entered into Amendment No. 4 to its Fourth Amended and Restated Credit Facility on January 15, 2008, thereby expanding its revolving credit facility to $750,000,000. RGS also entered into Amendment No. 5 to its Fourth Amended and Restated Credit Facility on February 13, 2008, expanding its revolving credit facility to $900,000,000 and availability for letters of credit to $100,000,000. The Partnership has the option to request an additional $250,000,000 in revolving and/or term loan commitments with ten business days written notice provided that no event of default has occurred or would result due to such increase, and all other additional conditions for the increase of the commitments set forth in the credit facility have been met. These amendments did not materially change other terms of the RGS revolving credit facility.

On September 15, 2008, Lehman Brothers Holdings, Inc. (“Lehman”) filed a petition in the United States Bankruptcy Court seeking relief under chapter 11 of the United States Bankruptcy Code. Of the amount committed by Lehman, the Partnership has borrowed all but $9,129,000. Lehman has declined requests to honor its remaining commitment, effectively reducing the total size of the Fourth Amended and Restated Credit Facility capacity to $890,871,000. If we repay any of the $25,871,000 we have already borrowed from Lehman, we will not be able to reborrow such amounts unless another lender assumes Lehman's commitment.

The outstanding balance of revolving debt under the credit facility bears interest at LIBOR plus a margin or Alternative Base Rate (equivalent to the U.S. prime lending rate) plus a margin, or a combination of both. The weighted average interest rates for the revolving loans and senior notes, including interest rate swap settlements, commitment fees, and amortization of debt issuance costs were 6.37 percent and 8.74 percent for the nine months ended September 30, 2008 and 2007, respectively and 6.15 percent and 8.80 percent for the three months ended September 30, 2008 and 2007, respectively. The senior notes bear interest at a fixed rate of 8.375 percent. The estimated fair market value of the senior notes was $321,750,000 and $272,594,000 as of September 30, 2008 and November 6, 2008, respectively.

The senior notes are guaranteed by the Partnership’s subsidiaries (the “Guarantors”) on December 12, 2006, the date the notes were issued. These note guarantees are the joint and several obligations of the Guarantors. A guarantor may not sell or otherwise dispose of all or substantially all of its properties or assets if such sale would cause a default under the terms of the senior notes. Events of default include nonpayment of principal or interest when due; failure to comply with certain limits on the payment of distributions; failure to make a change of control offer; failure to comply with reporting requirements according to SEC rules and regulations; and defaults on the payment of obligations under other indebtedness of $20,000,000 or more. Since certain subsidiaries do not guarantee the senior notes, the condensed consolidating financial statements of the guarantors and non-guarantors as of and for the nine months ended September 30, 2008 are disclosed below.

Condensed Consolidating Balance Sheets
September 30, 2008
Unaudited

	Guarantors	Non Guarantors	Elimination	Consolidated
ASSETS		(in thousands)		
Total current assets	$ 191,412	$ 17,829	$ -	$ 209,241
Property, plant and equipment, net	1,500,197	92,570	-	1,592,767
Total other assets	502,835	-	-	502,835
TOTAL ASSETS	$ 2,194,444	$ 110,399	$ -	$ 2,304,843
LIABILITIES & PARTNERS' CAPITAL				
Total current liabilities	$ 232,502	$ 4,167	$ -	$ 236,669
Long-term liabilities from risk management activities	6,170	-	-	6,170
Other long-term liabilities	15,591	-	-	15,591
Long-term debt	1,006,500	-	-	1,006,500

Minority interest	12,389	-	-	12,389
Partners' capital	921,292	106,232	-	1,027,524
TOTAL LIABILITIES & PARTNERS' CAPITAL	$ 2,194,444	$ 110,399	$ -	$ 2,304,843

Condensed Consolidating Statements of Operations
For the Nine Months Ended September 30, 2008
Unaudited

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Total revenues	$ 1,465,086	$ 34,029	$ -	$ 1,499,115
Total operating costs and expenses	1,353,211	28,559	-	1,381,770
OPERATING INCOME	111,875	5,470	-	117,345
Interest expense, net	(48,261)	-	-	(48,261)
Other income and deductions, net	514	(64)	-	450
Minority interest	(165)	-	-	(165)
INCOME BEFORE INCOME TAXES	63,963	5,406	-	69,369
Income tax expense	142	-	-	142
NET INCOME	$ 63,821	$ 5,406	$ -	$ 69,227

Condensed Consolidating Statements of Cash Flow
For the Nine Months Ended September 30, 2008
Unaudited

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Net cash flows provided by (used in) operating activities	$ 151,061	$ (1,781)	$ -	$ 149,280
Net cash flows used in investing activities	(813,658)	(3,368)	-	(817,026)
Net cash flows provided by financing activities	649,594	-	-	649,594

6. Equity Offering
On August 1, 2008, the Partnership sold 9,020,909 common units for an average price of $22.18 per unit under the Partnership's universal shelf registration statement. The Partnership received $204,133,000 in proceeds, inclusive of the General Partner's proportionate capital contribution of $4,082,653. The net proceeds were used to repay indebtedness under the Partnership's revolving credit facility. An affiliate of GECC purchased 2,272,727 of these common units. As of September 30, 2008, the Partnership has incurred $34,000 in costs related to this equity offering.

7. Commitments and Contingencies
Legal. The Partnership 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 Partnership's business, financial condition, results of operations or cash flows.

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

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

Escrow Payable. At September 30, 2008, $1,507,000 remained in escrow pending the completion by El Paso of environmental remediation projects pursuant to the purchase and sale agreement ("El Paso PSA") related to assets in north Louisiana and the mid-continent area. In the El Paso PSA, El Paso indemnified the predecessor of our operating partnership, RGS, against losses arising from pre-closing and known environmental liabilities subject to a limit of $84,000,000 and certain deductible limits. Upon completion of a Phase II environmental study, the Partnership notified El Paso of remediation obligations amounting to $1,800,000 with respect to known environmental matters and $3,600,000 with respect to pre-closing environmental liabilities.

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

Nexus Escrow. At September 30, 2008, $8,535,000 is included in an escrow account as security to the Partnership for a period of one year against indemnification obligations and any purchase price adjustments related to the Nexus Acquisition.

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

TCEQ Notice of Enforcement. On February 15, 2008, the TCEQ issued a NOE concerning one of the Partnership's processing plants located in McMullen County, Texas (the "Plant"). The NOE alleges that, between March 9, 2006, and May 8, 2007, the Plant experienced 15 emission events of various durations from four hours to 41 days, which were not reported to TCEQ and other agencies within 24 hours of occurrence. On April 3, 2008, TCEQ presented the Partnership with a written offer to settle the allegation in the NOE in exchange for payment of an administrative penalty of $480,000. The Partnership was unable to settle this matter on a satisfactory basis and the TCEQ has referred the matter for further proceedings.

RIGS FERC Petition. On April 29, 2008, RIGS filed a petition with the FERC seeking approval to maintain its maximum Section 311 transportation rates for firm and interruptible services as follows: Firm Service – reservation fee of $4.5625 per MMBtu monthly ($0.15 per MMBtu daily) and commodity fee of $0.05 per MMBtu; Interruptible Service – transportation fee of $0.20 per MMBtu; and Fuel Retention - up to two percent of receipts. The rate filing was required by a FERC Letter Order issued on September 26, 2005, which approved a settlement in which RIGS agreed to justify its existing rates or establish new rates for Section 311 services by May 1, 2008.

RIGS reached a settlement with FERC Staff on the 2008 petition, and on September 23, 2008, the FERC approved the settlement. The settlement provided for the continuation of RIGS existing maximum transportation rates and a reduction in RIGS' maximum fuel retention to one and a one-half percent effective May 1, 2008. The settlement permits RIGS' maximum fuel retention rate to increase to two percent when new compression is added to the RIGS system. As part of the settlement, RIGS also agreed to fully support its requested maximum fuel retention percentage in its next rate filing and to re-justify or establish new rates for Section 311 service by May 1, 2011. The triennial rate review requirement is a standard settlement provision in most intrastate pipeline rate proceedings for Section 311 service.

Keyes Litigation. In August 2008, Keyes Helium Company, LLC ("Keyes") filed suit against Regency Gas Services LP, the Partnership, and the General Partner. Keyes entered into an output contract with the Partnership's predecessor in 1996 under which it purchased all of the helium produced at the Lakin processing plant in southwest Kansas. In September 2004, the Partnership decided to shut down the Lakin plant and contract with a third party for the processing of volumes processed at Lakin, as a result of which the Partnership no longer delivered any helium to Keyes. As a result, Keyes alleges it is entitled to an unspecified amount of damages for the costs of covering its purchases of helium. The Partnership filed an answer to this lawsuit and plans to defend itself vigorously.

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

Purchase Commitments. At September 30, 2008, the Partnership has purchase obligations totaling $428,454,000, of which $148,924,000 relate to the purchase of major compression components unrelated to the expansion of RIGS, referred to in this document as the Haynesville Expansion Project, that extend until the year ending December 31, 2010 and $279,530,000 of commitments related to the Haynesville Expansion Project that extend until the year ending December 31, 2009. Some of these commitments have cancellation provisions.

8. Related Party Transactions

The employees operating the assets of the Partnership and its subsidiaries and substantially all those providing staff and support services are employees of the General Partner and other affiliates of the Partnership. Pursuant to the

Partnership Agreement, the General Partner receives a monthly reimbursement for all direct and indirect expenses that it incurs on behalf of the Partnership. Reimbursements of $7,284,000 and $7,169,000 were recorded in the Partnership’s financial statements during the three months ended September 30, 2008 and 2007, respectively, and reimbursements of $22,605,000 and $20,408,000 were recorded in the Partnership’s financial statements during the nine months ended September 30, 2008 and 2007, respectively, as operating expenses or general and administrative expenses, as appropriate.

In conjunction with distributions by the Partnership to its limited and general partner interests, GE EFS and affiliates received cash distributions of $25,396,000 and $7,212,000 during the nine months ended September 30, 2008 and 2007, respectively, as result of their ownership interests in the Partnership.

In conjunction with distributions by the Partnership to its limited and general partner interests, HM Capital Partners and affiliates received cash distributions of $10,308,000 and $21,215,000 during the nine months ended September 30, 2008 and 2007, respectively, as a result of their ownership interests in the Partnership. In September 2008, HM Capital Partners and affiliates sold 7,100,000 common units, reducing their ownership percentage to an amount less than ten percent of the Partnership's outstanding common units. As a result of this sale, HM Capital Partners is no longer a related party of the Partnership.

In conjunction with distributions by the Partnership to its limited and general partner interests, certain members of management received cash distributions of $1,382,000 in the nine months ended September 30, 2008 as a result of their ownership interests in the Partnership.

9. Segment Information

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

The transportation segment uses pipelines to transport natural gas from receipt points on its system to interconnections with larger pipelines or trading hubs and other markets. The Partnership performs transportation services for shipping customers under firm or interruptible arrangements. In either case, revenues are primarily fee based and involve minimal direct exposure to commodity price fluctuations. The Partnership also purchases natural gas at the inlets to the pipeline and sells this gas at its outlets. The north Louisiana intrastate pipeline operated by this segment serves the Partnership's gathering and processing facilities in the same area and those transactions create a portion of the intersegment revenues shown in the table below.

The contract compression segment includes designing, sourcing, owning, insuring, installing, operating, servicing, repairing, and maintaining compressors and related equipment, with a focus on meeting the complex requirements of field-wide compression applications, as opposed to targeting the compression needs of individual wells within a field. These field-wide applications include compression for natural gas gathering, natural gas lift for crude oil production and natural gas processing. Revenues in this segment are fee-based, with minimal direct exposure to commodity price risk. The contract compression operations are primarily located in Texas, Louisiana, and Arkansas. The contract compression segment also provides services to certain operations in the gathering and processing segment, creating a portion of the intersegment revenues shown in the table below.

Management evaluates the performance of each segment and makes capital allocation decisions through the separate consideration of segment margin and operation and maintenance expenses. Segment margin, for the gathering and processing and for the transportation segments, is defined as total revenues, including service fees, less cost of sales. In the contract compression segment, segment margin is defined as revenues minus direct costs, which primarily consist of compressor repairs. Management believes segment margin is an important measure because it directly relates to volume, commodity price changes and revenue generating horsepower. Operation and maintenance expenses are a separate measure used by management to evaluate performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of operation and maintenance expenses. These expenses fluctuate depending on the activities performed during a specific period. The Partnership does not deduct operation and maintenance expenses from total revenues in calculating segment margin because management separately evaluates commodity volume and price changes in segment margin.

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

	Gathering and Processing	Transportation	Contract Compression	Corporate	Eliminations	Total
			(in thousands)			
External Revenue						
For the three months ended September 30, 2008	$ 377,482	$ 133,620	$ 36,073	$ -	$ -	$ 547,175
For the three months ended September 30, 2007	199,717	96,107	-	-	-	295,824
For the nine months ended September 30, 2008	977,773	427,326	94,016	-	-	1,499,115
For the nine months ended September 30, 2007	590,796	264,285	-	-	-	855,081
Intersegment Revenue						
For the three months ended September 30, 2008	-	64,685	-	-	(64,685)	-
For the three months ended September 30, 2007	-	23,782	-	-	(23,782)	-
For the nine months ended September 30, 2008	-	147,440	-	-	(147,440)	-
For the nine months ended September 30, 2007	-	71,783	-	-	(71,783)	-
Cost of Sales						
For the three months ended September 30, 2008	290,840	178,587	3,423	-	(64,685)	408,165
For the three months ended September 30, 2007	154,127	104,601	-	-	(23,782)	234,946
For the nine months ended September 30, 2008	790,635	516,551	8,695	-	(147,440)	1,168,441
For the nine months ended September 30, 2007	475,329	293,098	-	-	(71,783)	696,644
Segment Margin						
For the three months ended September 30, 2008	86,642	19,718	32,650	-	-	139,010
For the three months ended September 30, 2007	45,590	15,288	-	-	-	60,878
For the nine months ended September 30, 2008	187,138	58,215	85,321	-	-	330,674
For the nine months ended September 30, 2007	115,467	42,970	-	-	-	158,437
Operation and Maintenance						
For the three months ended September 30, 2008	25,218	(927)	9,397	-	-	33,688
For the three months ended September 30, 2007	16,688	1,446	-	-	-	18,134
For the nine months ended September 30, 2008	63,656	1,931	29,462	-	-	95,049
	36,285	4,746	-	-	-	41,031

For the nine months ended September 30, 2007						
Depreciation and Amortization						
For the three months ended September 30, 2008	15,114	3,532	7,537	239	-	26,422
For the three months ended September 30, 2007	11,218	3,447	-	328	-	14,993
For the nine months ended September 30, 2008	43,028	10,519	20,370	721	-	74,638
For the nine months ended September 30, 2007	28,146	10,054	-	923	-	39,123
Assets						
September 30, 2008	1,080,035	331,369	848,333	45,106	-	2,304,843
December 31, 2007	886,477	329,862	-	62,071	-	1,278,410
Goodwill						
September 30, 2008	67,079	34,243	164,668	-	-	265,990
December 31, 2007	59,832	34,243	-	-	-	94,075
Expenditures for Long-Lived Assets						
For the nine months ended September 30, 2008	108,330	92	133,367	1,871	-	243,660
For the nine months ended September 30, 2007	100,012	8,269	-	702	-	108,983

The table below provides a reconciliation of total segment margin to net income (loss), the most comparable GAAP measure.

	Three Months Ended		Nine Months Ended	
	September 30, 2008	September 30, 2007	September 30, 2008	September 30, 2007
	(in thousands)			
Net income (loss)	$ 48,907	$ (9,832)	$ 69,227	$ (18,391)
Add (deduct):				
Operation and maintenance	33,688	18,134	95,049	41,031
General and administrative	13,976	6,983	38,784	32,928
Loss (gain) on assets sales, net	(34)	(777)	434	1,562
Management services termination fee	-	-	3,888	-
Transaction expenses	2	-	536	-
Depreciation and amortization	26,422	14,993	74,638	39,123
Interest expense, net	16,072	10,894	48,261	41,740
Loss on debt refinancing	-	21,200	-	21,200
Minority interest	162	156	165	130
Other income and deductions, net	(118)	(713)	(450)	(951)
Income tax expense (benefit)	(67)	(160)	142	65
Total segment margin	$ 139,010	$ 60,878	$ 330,674	$ 158,437

10. Equity-Based Compensation

In December 2005, the General Partner approved a long-term incentive plan ("LTIP") for the Partnership's employees, directors, and consultants covering an aggregate of 2,865,584 common units. LTIP awards generally vest on the basis of one-fourth of the award each year. Excluding forfeitures, the Partnership expects to recognize $20,561,000 of compensation expense related to the non-vested grants over a weighted average period of three years and two months. All outstanding options are vested and expire ten years after the grant date.

The Partnership makes distributions to non-vested restricted common units at the same rate as the common units. Restricted common units are subject to contractual restrictions against transfer which lapse over time; non-vested restricted units are subject to forfeitures on termination of employment. Upon exercise of the common unit options, the Partnership anticipates settling these obligations with common units. In the nine months ended September 30, 2008, two former executives of the Partnership exercised 135,000 unit options.

The common unit options and restricted (non-vested) unit activity for the nine months ended September 30, 2008 are as follows.

Common Unit Options	Units	Weighted Average Exercise Price	Weighted Average Contractual Term (Years)	Aggregate Intrinsic Value * (in thousands)
Outstanding at beginning of period	738,668	$ 21.05		
Granted	-	-		
Exercised	(245,150)	20.55		$ 1,719
Forfeited or expired	(15,400)	22.50		-
Outstanding at end of period	478,118	21.25	7.52	-
Exercisable at end of period	478,118	21.25		

* Intrinsic value equals the closing market price of a unit less the option strike price, multiplied by the number of unit options outstanding as of the end of the period presented. Unit options with an exercise price greater than the end of the period closing market price are excluded. The intrinsic value for exercised common unit options is calculated by multiplying the difference between the market price on the date of exercise and option strike price by the number of common unit options exercised.

Restricted (Non-Vested) Units	Units	Weighted Average Grant Date Fair Value
Outstanding at beginning of period	397,500	$ 31.62
Granted	473,300	28.15
Vested	(85,000)	31.75
Forfeited or expired	(59,500)	30.85
Outstanding at end of period	726,300	29.41

11. Fair Value Measures

On January 1, 2008, the Partnership adopted the provisions of SFAS No. 157 for financial assets and liabilities. SFAS No. 157 became effective for financial assets and liabilities on January 1, 2008. On January 1, 2009, the Partnership will apply the provisions of SFAS No. 157 for non-recurring fair value measurements of non-financial assets and liabilities, such as goodwill, indefinite-lived intangible assets, property, plant and equipment and asset retirement obligations. SFAS No. 157 defines fair value, thereby eliminating inconsistencies in guidance found in various prior accounting pronouncements, and increases disclosures surrounding fair value calculations.

SFAS No. 157 establishes a three-tiered fair value hierarchy that prioritizes inputs to valuation techniques used in fair value calculations. The three levels of inputs are defined as follows:

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

SFAS No. 157 encourages entities to maximize the use of observable inputs and minimize the use of unobservable inputs. If a financial instrument uses inputs that fall in different levels of the hierarchy, the instrument will be categorized based upon the lowest level of input that is significant to the fair value calculation.

The Partnership's financial assets and liabilities measured at fair value on a recurring basis are risk management assets and liabilities related to interest rate and commodity swaps. Risk management assets and liabilities are valued using discounted cash flow techniques. These techniques incorporate Level 1 and Level 2 inputs such as future interest rates and commodity prices. These market inputs are utilized in the discounted cash flow calculation considering the instrument's term, notional amount, discount rate and credit risk and are classified as Level 2 in the hierarchy. The Partnership has no financial assets and liabilities as of September 30, 2008 valued based on inputs classified as Level 3 in the hierarchy.

12. Subsequent Events

Partner Distributions. On October 24, 2008, the Partnership announced a distribution of $0.445 per common and subordinated unit including units equivalent to the General Partner's two percent interest in the Partnership, and an aggregate distribution of approximately $577,000 with respect to incentive distribution rights, payable on November 14, 2008 to unitholders of record at the close of business on November 7, 2008.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

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

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

RECENT DEVELOPMENTS.

We completed three acquisitions in the nine months ended September 30, 2008.

FrontStreet Hugoton LLC. On January 7, 2008, the Partnership acquired all of the outstanding equity and minority interest (the "FrontStreet Acquisition") of FrontStreet from ASC and EnergyOne. FrontStreet owns a gas gathering system located in Kansas and Oklahoma, which is operated by a third party.

The total purchase price consisted of (a) 4,701,034 Class E common units of the Partnership issued to ASC in exchange for its 95 percent interest and (b) $11,752,000 in cash to EnergyOne in exchange for its five percent minority interest and the termination of a management services contract valued at $3,888,000. The Partnership financed the cash portion of the purchase price with borrowings under its revolving credit facility.

In connection with the FrontStreet Acquisition, the Partnership amended the Partnership Agreement to create the Class E common units. The Class E common units have the same terms and conditions as the Partnership's common units, except that the Class E common units are not entitled to participate in earnings or distributions of operating surplus by the Partnership. The Class E common units were issued in a private placement conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933 as afforded by Section 4(2) thereof. The Class E common units converted into common units on a one-for-one basis on May 5, 2008.

Because the acquisition of ASC's 95 percent interest is a transaction between commonly controlled entities (i.e., the buyer and the seller were each affiliates of GECC), the Partnership accounted for this portion of the acquisition in a manner similar to the pooling of interest method. Under this method of accounting, our financial statements reflected historical balance sheet data for both the Partnership and FrontStreet instead of reflecting the fair market value of FrontStreet's assets and liabilities. Further, certain transaction costs that would normally be capitalized were expensed. Common control between the Partnership and FrontStreet began on June 18, 2007.

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

The total purchase price paid by the Partnership for the partnership interests of CDM consisted of (a) the issuance of an aggregate of 7,276,506 Class D common units of the Partnership, which were valued at $219,590,000 and (b) an aggregate of $478,445,000 in cash, $316,500,000 of which was used to retire CDM's debt obligations. Of the Class D common units issued, 4,197,303 Class D common units were deposited with an escrow agent pursuant to an escrow agreement. Such common units constitute security to the Partnership for a period of one year after the closing with respect to any obligations under the Merger Agreement, including obligations for breaches of representation, warranties and covenants.

In connection with the CDM merger, the Partnership amended the Partnership Agreement to create the Class D common units. The Class D common units have the same terms and conditions as the Partnership's common units, except that the Class D common units are not entitled to participate in distributions of operating surplus by the Partnership. The Class D common units automatically convert into common units on a one-for-one basis on the close of business on the first business day after the record date for the quarterly distribution on the common units for the quarter ending December 31, 2008. The Class D common units were issued in a private placement conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933 under Section 4(2) thereof.

Nexus Gas Holdings, LLC. On March 25, 2008, the Partnership acquired Nexus ("Nexus Acquisition") by merger for $88,486,000 in cash, including customary closing adjustments. Nexus Gas Partners LLC, the sole member of Nexus prior to the merger ("Nexus Member"), deposited $8,500,000 in an escrow account as security to the Partnership for a period of one year against indemnification obligations and any purchase price adjustment. The Partnership funded the Nexus Acquisition through borrowings under its revolving credit facility.

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

RIGS FERC Petition. On April 29, 2008, RIGS filed a petition with the FERC seeking approval to maintain its maximum Section 311 transportation rates for firm and interruptible services as follows: Firm Service – reservation fee of $4.5625 per MMBtu monthly ($0.15 per MMBtu daily) and commodity fee of $0.05 per MMBtu; Interruptible Service – transportation fee of $0.20 per MMBtu; and Fuel Retention - up to two percent of receipts. The rate filing was required by a FERC Letter Order issued on September 26, 2005, which approved a settlement in which RIGS agreed to justify its existing rates or establish new rates for Section 311 services by May 1, 2008.

RIGS reached a settlement with FERC Staff on the 2008 petition, and on September 23, 2008, the FERC approved the settlement. The settlement provided for the continuation of RIGS existing maximum transportation rates and a reduction in RIGS' maximum fuel retention to one and a one-half percent effective May 1, 2008. The settlement permits RIGS' maximum fuel retention rate to increase to two percent when new compression is added to the RIGS system. As part of the settlement, RIGS also agreed to fully support its requested maximum fuel retention percentage in its next rate filing and to re-justify or establish new rates for Section 311 service by May 1, 2011. The triennial rate review requirement is a standard settlement provision in most intrastate pipeline rate proceedings for Section 311 service.

TCEQ Notice of Enforcement. On February 15, 2008, the TCEQ issued a NOE concerning one of the Partnership's processing plants located in McMullen County, Texas (the "Plant"). The NOE alleges that, between March 9, 2006, and May 8, 2007, the Plant experienced 15 emission events of various durations from four hours to 41 days, which were not reported to TCEQ and other agencies within 24 hours of occurrence. On April 3, 2008, TCEQ presented the Partnership with a written offer to settle the allegation in the NOE in exchange for payment of an administrative penalty of $480,000. The Partnership was unable to settle this matter on a satisfactory basis and the TCEQ has referred the matter for further proceedings.

Equity Offering. On August 1, 2008, the Partnership issued 9,020,909 common units and received $204,133,000 in proceeds, inclusive of the General Partner's proportionate capital contribution. The net proceeds were used to repay indebtedness under the Partnership's revolving credit facility. The common units were issued under the Partnership's universal shelf registration statement. An affiliate of GECC purchased 2,272,727 of these common units. As of September 30, 2008, the Partnership has incurred $34,000 in costs related to this equity offering.

Haynesville Expansion Project. The Haynesville Shale, located generally in northwest Louisiana, has become one of the most active new natural gas plays in the United States. We believe that there is insufficient transportation capacity in place to accommodate the level of production expected in the Haynesville Shale and that significant investment in new infrastructure is required.

On September 9, 2008, we announced our plans to expand RIGS to transport gas from the Haynesville Shale to market. The Haynesville Expansion Project was expected to add 204 miles of pipeline ranging in diameter from 24 to 42 inches and 49,000 horsepower of compression. We anticipated completing the project in two phases. The first phase of the project was to be completed in the first half of 2009 and would have added approximately 300 MMcf/d of capacity by constructing additional pipeline loops and adding compression to the existing RIGS system. The second phase of the project was to be completed in the first quarter of 2010 and would have added an incremental 1.15 Bcf/d. The total cost was expected to be approximately $1.1 billion, with phase one comprising approximately $375,000,000 of the total cost.

In light of the recent turmoil in the economic environment, we have scaled back our plans to expand RIGS to transport gas from the Haynesville Shale to market. The Haynesville Expansion Project is now expected to add 128 miles of pipeline ranging in diameter from 36 to 42 inches and 12,500 horsepower of compression. We anticipate completing the project in one phase by December 31, 2009. This project is expected to add approximately 1.1 Bcf/d of capacity. The total cost is expected to be $650,000,000, exclusive of capitalized interest and labor. Our ability to construct this project is subject to our obtaining financing and entering into agreements with shippers. See "Liquidity and Capital Resources" and "Risk Factors" for discussion of the RIGS expansion financing.

See "Liquidity and Capital Resources" and "Risk Factors" for discussion on the recent credit market disruption and decreases in commodity prices.

OUR OPERATIONS. We manage our business and analyze and report our results of operations through three business segments.

- Gathering and Processing: We provide "wellhead-to-market" services to producers of natural gas, which include transporting raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate NGLs from the raw natural gas and selling or delivering the pipeline-quality natural gas and NGLs to various markets and pipeline systems;
- Transportation: We deliver natural gas from northwest Louisiana to more favorable markets in northeast Louisiana through our 320-mile Regency Intrastate Pipeline system; and
- Contract Compression: We provide customers with turn-key natural gas compression services to maximize their natural gas and crude oil production, throughput, and cash flow. Our integrated solutions include a comprehensive assessment of a customer's natural gas contract compression needs and the design and installation of a compression system that addresses those particular needs. We are responsible for the installation and ongoing operation, service, and repair of our compression units, which we modify as necessary to adapt to our customers' changing operating conditions.

HOW WE EVALUATE OUR OPERATIONS. Our management uses a variety of financial and operational measurements to analyze our performance. We view these key performance indicators as important tools for evaluating the success of our operations and review these key performance indicators on a monthly basis for consistency and trends. For our gathering and processing and transportation segments, the key performance indicators include volumes, segment margin, and operating and maintenance expenses. For our contract compression segment, the key performance indicators include revenue generating horsepower, average horsepower per revenue generating compression unit, segment margin, and operation and maintenance expenses. Management also reviews EBITDA for each reportable segment and in total to analyze performance.

Volumes. We must continually obtain new supplies of natural gas to maintain or increase throughput volumes on our gathering and processing systems. Our ability to maintain existing supplies of natural gas and obtain new supplies is affected by (a) the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to our pipelines, (b) our ability to compete for volumes from successful new wells in other areas and (c) our ability to obtain natural gas that has been released from other commitments. We routinely monitor producer activities in the areas served by our gathering and processing systems to pursue new supply opportunities.

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

Revenue Generating Horsepower. Revenue generating horsepower growth is the primary driver for revenue growth in the contract compression segment, and it is also the base measure for evaluating our operational efficiency. Revenue generating horsepower is our total available horsepower less horsepower under contract that is not generating revenue and idle horsepower.

Average Horsepower per Revenue Generating Compression Unit. We calculate average horsepower per revenue generating compression unit as our revenue generating horsepower divided by the number of revenue generating compression units.

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

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

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

Total Segment Margin. Segment margin from gathering and processing, transportation, contract compression and inter-segment eliminations comprise total segment margin. We use total segment margin as a measure of performance. The reconciliation of the non-GAAP financial measure, total segment margin, to its most directly comparable GAAP measure, net income (loss), is included in Note 9, Segment Information, within the condensed consolidated financial statements included in Item 1 of this report.

Operation and Maintenance Expenses. Operation and maintenance 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 and maintenance expenses. These expenses are largely independent of the volumes flowing through our systems but fluctuate depending on the activities performed during a specific period. We do not deduct operation and maintenance from total revenues in calculating segment margin because we separately evaluate commodity volume and price changes in segment margin.

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

- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our unitholders and general 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 as an alternative to net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. EBITDA is the starting point in determining cash available for distribution, which is an important non-GAAP financial measure for a publicly traded master limited partnership. The following table reconciles the non-GAAP financial measure, EBITDA, to its most directly comparable GAAP measures, net loss and net cash flows provided by operating activities.

	Nine Months Ended	
	September 30, 2008	September 30, 2007
	(in thousands)	
Net cash flows provided by operating activities	$ 149,280	$ 49,181
Add (deduct):		
Depreciation and amortization, including debt issuance cost amortization	(76,751)	(40,627)
Write-off of debt issuance costs	-	(5,078)
Equity income and minority interest in earnings	(165)	(130)
Risk management portfolio valuation changes	1,007	(1,634)
Loss on asset sales	(434)	(1,562)
Unit based compensation expenses	(3,087)	(14,790)
Gain on insurance settlements	3,282	-
Changes in current assets and liabilities:		
Trade accounts receivables and accrued revenues	11,084	14,857
Other current assets	(38)	(251)
Trade accounts payable, accrued cost of gas and liquids, and related party payables	11,125	(15,171)
Other current liabilities	(22,448)	(4,132)
Other assets and liabilities	(3,628)	946
Net income (loss)	$ 69,227	$ (18,391)
Add:		
Interest expense, net	48,261	41,740
Depreciation and amortization	74,638	39,123
Income tax expense	142	65
EBITDA	$ 192,268	$ 62,537

CASH DISTRIBUTIONS. On October 24, 2008, the Partnership announced a distribution of $0.445 per common and subordinated unit including units equivalent to the General Partner’s two percent interest in the Partnership, and an aggregate distribution of approximately $577,000 with respect to incentive distribution rights, payable on November 14, 2008 to unitholders of record at the close of business on November 7, 2008.

RESULTS OF OPERATIONS

Three Months Ended September 30, 2008 vs. Three Months Ended September 30, 2007

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

	Three Months Ended			
	September 30, 2008	September 30, 2007	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$ 547,175	$ 295,824	$ 251,351	85%
Cost of sales	408,165	234,946	173,219	74
Total segment margin (1)	139,010	60,878	78,132	128
Operation and maintenance	33,688	18,134	15,554	86
General and administrative	13,976	6,983	6,993	100
Loss on asset sales, net	(34)	(777)	743	96

Transaction expenses	2	-	2	N/M
Depreciation and amortization	26,422	14,993	11,429	76
Operating income	64,956	21,545	43,411	201
Interest expense, net	(16,072)	(10,894)	(5,178)	48
Loss on debt refinancing	-	(21,200)	21,200	100
Other income and deductions, net	118	713	(595)	83
Minority interest	(162)	(156)	(6)	4
Income tax benefit	(67)	(160)	93	58
Net income (loss)	$ 48,907	$ (9,832)	$ 58,739	597%
System inlet volumes (MMbtu/d) (2)	1,604,655	1,377,453	227,202	16
Revenue generating horsepower (3)	742,804	-	N/A	N/A

(1) For a reconciliation of total segment margin to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read "Item 1. Financial Statements – Note 9, Segment Information."
(2) System inlet volumes include total volumes taken into both our gathering and processing and transportation systems.
(3) Revenue generating horsepower is our total available horsepower less horsepower under contract that is not generating revenue and idle horsepower.
N/M – not meaningful.
N/A – not applicable as we acquired the business in January 2008.

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

	Three Months Ended September 30, 2008	September 30, 2007	Change	Percent
	(in thousands except percentage and volume data)			
Segment Financial and Operating Data:				
Gathering and Processing Segment				
Financial data:				
Segment margin	$ 86,642	$ 45,590	$ 41,052	90%
Operation and maintenance	25,218	16,688	8,530	51
Operating data:				
Throughput (MMbtu/d) (1)	1,082,139	882,008	200,131	23
NGL gross production (Bbls/d)	21,386	22,655	(1,269)	6
Transportation Segment				
Financial data:				
Segment margin	$ 19,718	$ 15,288	$ 4,430	29
Operation and maintenance	(927)	1,446	(2,373)	164
Operating data:				
Throughput (MMbtu/d) (1)	795,104	788,789	6,315	1
Contract Compression Segment				
Financial data:				
Segment margin	$ 32,650	$ -	N/A	N/A
Operation and maintenance	9,397	-	N/A	N/A

(1) Combined throughput volumes for the gathering and processing and transportation segments vary from consolidated system inlet volumes due to inter-segment eliminations between the two segments.
N/A – not applicable as we acquired the business in January 2008.

The tables below contain key performance indicators for the contract compression segment.

	For the Period Ended March 31, 2008	June 30, 2008	September 30, 2008
Revenue generating horsepower	615,852	669,804	742,804
Revenue generating units	725	789	873
Average horsepower	849	849	851

In addition to the revenue generating horsepower and units owned and operated by the contract compression segment disclosed in the above table, the contract compression segment operates 186,601 horsepower owned by the gathering and processing and transportation segments.

For the Period Ended September 30, 2008

Horsepower Range	Revenue Generating Horsepower	Percentage of Revenue Generating Horsepower	Number of Units
0-499	56,178	8%	337
500-999	82,016	11%	132
1,000+	604,610	81%	404
	742,804	100%	873

Net Income. Net income for the three months ended September 30, 2008 was $48,907,000 compared to net loss of $9,832,000 for the three months ended September 30, 2007, a $58,739,000 increase. The increase in net income was primarily due to an increase in total segment margin of $78,132,000 and the absence in the current period of $21,200,000 loss on debt refinancing for the early termination penalty associated with the redemption of 35 percent of our senior notes incurred during the three months ended September 30, 2007, partially offset by:

- an increase in operation and maintenance expense of $15,554,000 primarily due to operation and maintenance expenses in the contract compression segment assets that were acquired in January 2008 and an increase in employee-related expenses mainly in the gathering and processing segment;
- an increase in depreciation and amortization expense of $11,429,000 primarily due to our CDM, FrontStreet and Nexus acquisitions and organic growth projects;
- an increase in general and administrative expenses of $6,993,000 primarily due to our contract compression assets acquired in January 2008 and increased employee-related expenses; and
- an increase in interest expense of $5,178,000 primarily due to increased levels of borrowings.

Segment Margin. Total segment margin for the three months ended September 30, 2008 increased $78,132,000 compared with the three months ended September 30, 2007. This increase was attributable to an increase of $41,052,000 in gathering and processing segment margin, an increase of $4,430,000 in transportation segment margin and the addition of $32,650,000 in contract compression segment margin in the three months ended September 30, 2008, as further discussed below.

Gathering and processing segment margin increased to $86,642,000 for the three months ended September 30, 2008 from $45,590,000 for the three months ended September 30, 2007. The major components of this increase were as follows:

- $24,581,000 from non-cash changes in the value of certain risk management contracts related to our hedging programs;
- $7,105,000 from increased throughput volumes in north Louisiana;
- $5,185,000 from increased sulphur prices;
- $3,610,000 from organic growth projects placed into service in south Texas that did not exist in the prior period;
- $2,582,000 from the operations of our Nexus assets; and were partially offset by
- $2,011,000 decrease from various other sources.

Transportation segment margin increased to $19,718,000 for the three months ended September 30, 2008 from $15,288,000 for the three months ended September 30, 2007. The major components of this increase were as follows:

- $1,992,000 in increased margins associated with our limited marketing function;
- $1,482,000 from increased operational efficiencies coupled with increased commodity prices; and
- $993,000 from increased throughput volumes and changes to contract mix.

Contract compression segment margin was $32,650,000 in the three months ended September 30, 2008 which consisted of $36,073,000 of operating revenues and $3,423,000 of direct operating costs.

Operation and Maintenance. Operation and maintenance expense increased to $33,688,000 in the three months ended September 30, 2008 from $18,134,000 for the corresponding period in 2007, an 86 percent increase. This increase is primarily the result of the following factors:

- $9,397,000 related to our contract compression business acquired in January 2008;
- $6,553,000 related to the gathering and processing segment associated primarily with an increased amount of assets due to organic growth projects since September 30, 2007 and increased compressor and other maintenance expenses in 2008;
- $983,000 increase in gathering and processing segment employee-related expenses primarily related to increased bonus accruals and employer benefit payments;
- $631,000 increase in contractor expense in the transportation segment due to compressor maintenance;
- $536,000 related to our FrontStreet assets, which is operated by a third party;
- $267,000 increase in utility expense due to higher costs; and were partially offset by
- $3,134,000 in insurance proceeds received in the three months ended September 30, 2008 related to a compressor fire on the RIGS system.

General and Administrative. General and administrative expense increased to $13,976,000 in the three months ended September 30, 2008 from $6,983,000 for the same period in 2007, a 100 percent increase. This increase is primarily due to:

- $4,427,000 related to our contract compression assets acquired January 2008; and
- $2,185,000 increase in employee-related expenses primarily due to increased employer benefit payments and bonus accruals.

Depreciation and Amortization. Depreciation and amortization expense increased to $26,422,000 in the three months ended September 30, 2008 from $14,993,000 for the three months ended September 30, 2007, a 76 percent increase. The following factors contributed to this increase:

- $7,537,000 related to our contract compression business acquired in January 2008;
- $1,490,000 related to our FrontStreet assets which are now depreciated over a shorter useful life as compared to 2007;
- $1,386,000 related to various organic growth projects completed since September 30, 2007, primarily in the gathering and processing segment; and
- $1,016,000 related to our Nexus acquisition in March 2008.

Interest Expense, Net. Interest expense, net increased by $5,178,000, or 48 percent, in the three months ended September 30, 2008 compared to the same period in 2007. Interest expense, net increased by $7,228,000 due to increased levels of borrowings, partially offset by a decrease of $3,941,000 primarily attributable to lower interest rates and $1,891,000 related to a decrease in capitalized interest and a realized gain on a swap settlement in the three months ended September 30, 2007.

Nine Months Ended September 30, 2008 vs. Nine Months Ended September 30, 2007

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

	Nine Month Ended			
	September 30, 2008	September 30, 2007	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$ 1,499,115	$ 855,081	$ 644,034	75%
Cost of sales	1,168,441	696,644	471,797	68
Total segment margin (1)	330,674	158,437	172,237	109
Operation and maintenance	95,049	41,031	54,018	132
General and administrative	38,784	32,928	5,856	18
Loss on asset sales, net	434	1,562	(1,128)	72
Management service termination fee	3,888	-	3,888	NM
Transaction expenses	536	-	536	NM
Depreciation and amortization	74,638	39,123	35,515	91
Operating income	117,345	43,793	73,552	168
Interest expense, net	(48,261)	(41,740)	(6,521)	16
Loss on debt refinancing	-	(21,200)	21,200	100
Other income and deductions, net	450	951	(501)	53
Minority interest	(165)	(130)	(35)	27
Income tax expense	142	65	77	118
Net income (loss)	$ 69,227	$ (18,391)	$ 87,618	476%
System inlet volumes (MMbtu/d) (2)	1,500,714	1,248,773	251,942	20
Revenue generating horsepower (3)	742,804	-	N/A	N/A

(1) For a reconciliation of total segment margin to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read "Item 1. Financial Statements – Note 9, Segment Information."
(2) System inlet volumes include total volumes taken into both our gathering and processing and transportation systems.
(3) Revenue generating horsepower is our total available horsepower less horsepower under contract that is not generating revenue and idle horsepower.
N/M – not meaningful.
N/A – not applicable as we acquired the business in January 2008.

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

	Nine Month Ended September 30, 2008	September 30, 2007	Change	Percent
	(in thousands except percentages and volume data)			
Segment Financial and Operating Data:				
Gathering and Processing Segment				
Financial data:				
Segment margin	$ 187,138	$ 115,467	$ 71,671	62%
Operation and maintenance	63,656	36,285	27,371	75
Operating data:				
Throughput (MMbtu/d) (1)	998,518	794,173	204,345	26
NGL gross production (Bbls/d)	22,323	21,233	1,090	5
Transportation Segment				
Financial data:				
Segment margin	$ 58,215	$ 42,970	$ 15,245	35
Operation and maintenance	1,931	4,746	(2,815)	59
Operating data:				
Throughput (MMbtu/d) (1)	773,562	757,367	16,195	2
Contract Compression Segment				
Financial data:				
Segment margin	$ 85,321	$ -	N/A	N/A
Operation and maintenance	29,462	-	N/A	N/A

(1) Combined throughput volumes for the gathering and processing and transportation segment vary from consolidated system inlet volumes due to inter-segment eliminations between the two segments.
N/A – not applicable as we acquired the business in January 2008.

Net Income. Net income for the nine months ended September 30, 2008 was $69,227,000 compared to net loss of $18,391,000 for the nine months ended September 30, 2007, a 476 percent increase. The increase in net income was primarily due to an increase in total segment margin of $172,237,000 and the absence in the current period of $21,200,000 loss on debt refinancing for the early termination penalty associated with the redemption of 35 percent of our senior notes incurred during the nine months ended September 30, 2007; partially offset by:

- an increase in operation and maintenance expense of $54,018,000 primarily due to operation and maintenance expenses related to our CDM and FrontStreet assets acquired in January 2008 and increased contractor and employee-related expenses in the gathering and processing segment;
- an increase in depreciation and amortization expense of $35,515,000 due to our CDM, FrontStreet and Nexus acquisitions and organic growth projects;
- an increase in general and administrative expense of $5,856,000, primarily due to the CDM and FrontStreet acquisitions and higher performance bonus accruals, reduced by the absence of a charge associated with the vesting of all outstanding LTIP grants incurred in the nine months ended September 30, 2007 when GE EFS acquired our general partner;
- an increase in interest expense of $6,521,000 primarily due to increased borrowing levels; and
- a payment of management contract services termination fee of $3,888,000 in the nine months ended September 30, 2008 related to the acquisition of FrontStreet.

Segment Margin. Total segment margin for the nine months ended September 30, 2008 increased $172,237,000 compared with the nine months ended September 30, 2007. This increase was attributable to an increase of $71,671,000 in gathering and processing segment margin, an increase of $15,245,000 in transportation segment margin and the addition of $85,321,000 in contract compression segment margin in the nine months ended September 30, 2008, as discussed below.

Gathering and processing segment margin increased to $187,138,000 for the nine months ended September 30, 2008 from $115,467,000 for the nine months ended September 30, 2007. The major components of this increase were as follows:

- $22,352,000 from the operations of FrontStreet assets which were acquired in January 2008, but accounted for in a manner similar to a pooling of interests from June 18, 2007. Thus, the results of the FrontStreet assets are only present for three and one-half months during the nine months ended September 30, 2007;
- $16,462,000 from organic growth projects placed into service in south Texas that did not exist in the prior period;
- $11,112,000 from increased throughput volumes in north Louisiana;
- $8,722,000 from increased sulfur prices;
- $5,373,000 from the operation of the Nexus assets acquired in March 2008; and
- $4,317,000 increase from non-cash changes in the value of certain risk management contracts.

Transportation segment margin increased to $58,215,000 for the nine months ended September 30, 2008 from $42,970,000 for the nine months ended September 30, 2007. The major components of this increase were as follows:

- $10,132,000 from increased operational efficiencies coupled with increased commodity prices;
- $3,665,000 from increased margins associated with our limited marketing function;
- $2,144,000 from increased throughput volumes and changes to contract mix; and
- $695,000 decrease from non cash changes in the value of certain risk management contracts.

Contract compression segment margin was $85,321,000 in the nine months ended September 30, 2008, which consisted of $94,016,000 of operating revenue and $8,695,000 of direct operating costs.

Operation and Maintenance. Operation and maintenance expense increased to $95,049,000 in the nine months ended September 30, 2008 from $41,031,000 for the corresponding period in 2007, a 132 percent increase. This increase is primarily the result of the following factors:

- $29,462,000 related to our contract compression business acquired in January 2008;
- $12,562,000 related to our FrontStreet assets, primarily contractor expense in the nine months ended September 30, 2008 compared to three and half month’s operations in 2007;
- $8,669,000 related to the gathering and processing segment associated primarily with an increased amount of assets due to organic growth projects since September 30, 2007 and increased compressor and other maintenance expenses in 2008;
- $3,577,000 increase in employee expenses primarily in the gathering and processing segment primarily related to increased employer benefit payments and bonus payments and accruals;
- $975,000 increase in utility expenses primarily in the gathering and processing segment due to higher electricity costs;
- $931,000 increase in property taxes related to our FrontStreet assets in the nine month ended September 30, 2008 versus three and half month in 2007;
- $976,000 increase in various other operation and maintenance expenses; and were partially offset by
- $3,134,000 in insurance proceeds received in August 2008 related to a 2007 compressor fire on the RIGS system in the transportation segment.

General and Administrative. General and administrative expense increased to $38,784,000 in the nine months ended September 30, 2008 from $32,928,000 for the same period in 2007, an 18 percent increase. In June 2007, the Partnership incurred a one-time charge of $11,928,000 associated with the vesting of all outstanding common unit options and restricted unit options upon a change in control, when GE EFS acquired our general partner. Absent this charge, general and administrative expenses increase by $17,784,000 primarily due to:

- $11,499,000 related to our contract compression business acquired in January 2008; and
- $5,743,000 increase in employee related expenses primarily due to increased bonus accruals and employer benefit payments.

Management Services Termination Fee. In the nine months ended September 30, 2008, we recorded a charge of $3,888,000 for the termination of a long-term management services contract associated with our FrontStreet acquisition.

Depreciation and Amortization. Depreciation and amortization expense increased to $74,638,000 in the nine months ended September 30, 2008 from $39,123,000 for the nine months ended September 30, 2007, a 91 percent increase. The increase in depreciation and amortization expense is due to the following factors:

- $20,370,000 related to our contract compression assets acquired January 2008;
- $7,176,000 related to our FrontStreet assets which are now depreciated over a shorter useful life as compared to 2007;
- $5,954,000 related to various organic projects completed since the June 2007, primarily in the gathering and processing segment; and
- $2,015,000 related to our Nexus acquisition in March 2008.

Interest Expense, Net. Interest expense, net increased $6,521,000, or 16 percent, in the nine months ended September 30, 2008 compared to the same period in 2007. Interest expense, net increased by $17,080,000 due to increased levels of borrowings, and $1,455,000 due to a decrease in capitalized interest versus the comparison period and a realized gain on a swap settlement in the nine months ended September 30, 2007 and decreased by $12,014,000 due to lower interest rates.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES. In addition to the information set forth in this report, further information regarding the Partnership's critical accounting policies and estimates is included in Item 7 of the Partnership's Annual Report on Form 10-K for the year ended December 31, 2007.

As-if Pooling of Interest Method of Accounting. We account for acquisitions where common control exists by following the as-if pooling method of accounting as described in SFAS No. 141, "Business Combinations." Under this method of accounting, we reflect the historical balance sheet data for both the acquirer and acquiree instead of reflecting the fair market value of acquiree's assets and liabilities. In common control acquisitions where a minority interest is also acquired, we use the purchase method of accounting for the minority interest. Further, certain transaction costs that would normally be capitalized are expensed.

Fair Value Measurements. On January 1, 2008, we adopted the provisions of SFAS No. 157 for financial assets and liabilities. SFAS No. 157 defines fair value, thereby eliminating inconsistencies in guidance found in various prior accounting pronouncements, and increases disclosures surrounding fair value calculations. The adoption of SFAS No. 157 for financial assets and liabilities did not have a material impact on our financial position or cash flows for the three months ended September 30, 2008.

SFAS No. 157 establishes a three-tiered fair value hierarchy that prioritizes inputs to valuation techniques used in fair value calculations. The three levels of inputs are defined as follows:

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

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

The Partnership's financial assets and liabilities measured at fair value on a recurring basis are risk management assets and liabilities related to interest rate and commodity swaps. Risk management assets and liabilities are valued using discounted cash flow techniques. These techniques incorporate Level 1 and Level 2 inputs such as future interest rates and commodity prices. These market inputs are utilized in the discounted cash flow calculation considering the instrument's term, notional amount, discount rate and credit risk and are classified as Level 2 in the hierarchy. The Partnership has no financial assets and liabilities as of September 30, 2008 valued based on inputs classified as Level 3 in the hierarchy.

OTHER MATTERS.

Information regarding the Partnership's commitments and contingencies are included in Note 7-Commitments and Contingencies to the condensed consolidated financial statements included in Item 1 of this report.

LIQUIDITY AND CAPITAL RESOURCES

We expect our sources of liquidity to include:

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

We have experienced, and expect to continue to experience, substantial capital expenditure and working capital needs, particularly as a result of our Haynesville Expansion Project. At September 30, 2008, the Partnership has purchase obligations totaling $428,454,000, of which $148,924,000 is related to the purchase of major compression components unrelated to the Haynesville Expansion Project, that extend until the year ending December 31, 2010 and $279,530,000 of which is related to the Haynesville Expansion Project that extend until the year ending December 31, 2009. Some of these commitments have cancellation provisions. We are in discussions with suppliers and vendors to reduce these commitments. Our planned capital expenditures for 2008 and 2009 are expected to exceed substantially the net cash generated by our operations. In addition to using borrowings under our revolving credit facility, in order to finance these planned capital expenditures, we will also need to raise additional financing from future equity or debt offerings to fund all of our budgeted capital expenditures for 2009.

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

Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to our current debt and reduced and, in some cases, ceased to provide funding to borrowers. For example, as a result of Lehman Brothers Holding, Inc., or Lehman, filing a petition under Chapter 11 of the U.S. Bankruptcy Code, a subsidiary of Lehman that is a committed lender under our credit facility has declined requests to honor its commitment to lend up to $35,000,000 under our credit facility. The total amounts available to us under our credit facility as of September 30, 2008 and October 31, 2008 were $225,614,000 and $207,353,000, respectively, which have been reduced by the amount of Lehman's commitment that is no longer available to us. If we repay any of the $25,871,000 we have already borrowed from Lehman, we may not be able to reborrow such amounts. We may be unable to utilize the full borrowing capacity under our credit facility if other lenders are not willing to provide additional funding to make up the portion of the credit facility commitments that Lehman’s subsidiary has refused to fund or if any of the remaining committed lenders are unable or unwilling to fund their respective portion of any funding request we make under our credit facility.

Further, although we obtained commitment letters for approximately $600,000,000 of debt financing for our Haynesville Expansion Project, those commitment letters were obtained prior to most of the disruption in the credit markets and were subject to the execution of definitive loan documentation and other terms and closing conditions. Given the recent disruption in the credit markets, we believe we will not be able to access these commitments. We expect to reduce our growth capital expenditures in 2009 and 2010, exclusive of the Haynesville Expansion Project, from approximately $300,000,000 per year to approximately $100,000,000 per year. We intend to finance all of our growth capital in the long-term with a debt to EBITDA ratio of approximately four times. As a result of our reduced capital expenditure plans, our need to access the debt and equity markets will be significantly reduced.

We are seeking alternative financing sources, which could delay the execution of our Haynesville Expansion Project and or have an adverse affect on our financing terms. In addition, producers in the area may decrease their activity levels in the area due to the current deterioration in the credit markets or the recent declines in the price for natural gas. To the extent producers in the area are unable to execute their expected drilling programs, the return on our investment from this project may not be as attractive as we anticipate.

Although we intend to move forward with our planned internal growth projects, including our Haynesville Expansion Project, we may further revise the timing and scope of these projects as necessary to adapt to existing economic conditions and the benefits expected to accrue to our unitholders from our expansion activities may be muted by substantial cost of capital increases during this period. Any delay of the Haynesville Expansion Project could result in our not being able to enter into contracts with the anchor shippers necessary for us to finance and construct the project. To the extent that we do not enter into definitive transportation agreements on satisfactory terms or to the extent producers in the area are unable to execute their exploratory drilling and development plans in this area, the return on our investment from this project may not be as attractive as we anticipate as we will still incur substantial costs for commitments we have made for materials and services. As a result of these costs our cash flows may decrease, which could impair our liquidity position and require us to reduce our distributions to unitholders.

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

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

Our working capital deficit increased by $9,063,000 from December 31, 2007 to September 30, 2008, primarily due to:

- an increase in other current liabilities of $22,448,000 primarily resulting from deferred revenues from our contract compression segment, increased accrued interest associated with the timing of interest payments on our senior notes and higher borrowing levels on our revolving credit facility, increased property tax accruals; and
- a decrease in cash and cash equivalents of $18,152,000.

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

- an increase in net risk management asset and liabilities of $23,346,000 due primarily to lower commodity prices associated with our derivatives portfolio and
- an increase in net accounts receivable and payable of $8,229,000 due primarily to increased total segment margin and the timing of cash receipts and disbursements.

Cash Flows from Operations. Net cash flows provided by operating activities increased $100,099,000, or 204 percent, for the nine months ended September 30, 2008 as compared to the nine months ended September 30, 2007. Our cash flows from operations increased primarily due to increased segment margin from our FrontStreet and CDM acquisitions in January 2008, our Nexus acquisition in late March 2008, our Pueblo acquisition in April 2007 and organic growth in our gathering and processing segment.

Cash Flows from Investing Activities. Net cash flows used in investing activities increased $679,922,000 in the nine months ended September 30, 2008 compared to the nine months ended September 30, 2007. Our increase in cash flows from investing activities was primarily attributable to the FrontStreet and CDM Acquisitions in January 2008, the Nexus Acquisition in March 2008 and higher growth and maintenance capital expenditures discussed in "Capital Requirements."

Cash Flows from Financing Activities. Net cash flows provided by financing activities increased $548,890,000 in the nine months ended September 30, 2008 compared to the nine months ended September 30, 2007, primarily due to increased borrowings under our revolving credit facility used to fund the FrontStreet, CDM and Nexus acquisitions. Also contributing to the increase in net cash flows provided by financing activities was the equity offering discussed below.

Equity Offering. On August 1, 2008 the Partnership sold 9,020,909 common units for an average price of $22.18 per unit. The Partnership received $204,133,000 in proceeds, inclusive of the General Partner's proportionate capital contribution of $4,082,653. The net proceeds were used to repay indebtedness under the Partnership's revolving credit facility and to fund growth capital projects. The common units were issued under the Partnership's universal shelf registration statement. An affiliate of GECC purchased 2,272,727 of these common units. As of September 30, 2008, the Partnership has incurred $34,000 in costs related to this equity offering.

Credit Ratings. Our credit ratings as of October 31, 2008 are provided in the table below.

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

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Capital Requirements

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 to extend their useful lives or to maintain existing system volumes and related cash flows.

Growth Capital Expenditures. In the nine months ended September 30, 2008, we incurred $231,461,000 of growth capital expenditures related to:

- $126,485,000 for the fabrication of new compression packages and ancillary assets for our contract compression segment;
- $102,029,000 for various projects in the gathering and processing segment, primarily in Louisiana and Texas; and
- $2,947,000 in our transportation segment for the Haynesville Expansion Project.

Our expected calendar year 2008 organic growth capital expenditures of $356,211,000 includes:

- $143,000,000 for additional compression in our contract compression segment;
- $116,264,000 for various projects in the gathering and processing segment; and
- $96,947,000 for the Haynesville Expansion Project in the transportation segment.

Maintenance Capital Expenditures. In the nine months ended September 30, 2008, we incurred $12,062,000 of maintenance capital expenditures. Maintenance capital expenditures primarily consist of compressor and equipment overhauls, as well as new well connects to our gathering systems, which replace volumes from naturally occurring depletion of wells already connected.

Contractual Obligations. As of September 30, 2008, we had borrowed $649,000,000 under our revolving credit facility primarily to finance our growth capital expenditures and first quarter 2008 acquisitions. The following table summarizes our total contractual cash obligations for long-term debt and purchase obligations as of September 30, 2008. This table excludes capital lease obligations as these amounts have not materially changed since December 31, 2007.

			Payment Period		
Contractual Cash Obligations	Total	2008	2009-2010	2011-2012	Thereafter
			(in thousands)		
Long-term debt (including interest) (1)	$ 1,257,303	$ 22,460	$ 119,797	$ 727,605	$ 387,441
Operating leases	9,560	-	1,506	1,721	6,333
Purchase obligations	428,454	143,173	285,281	-	-
Total (2) (3)	$ 1,695,317	$ 165,633	$ 406,584	$ 729,326	$ 393,774

(1) Assumes a constant LIBOR interest rate of 2.5 percent plus the applicable margin (2.0 percent as of September 30, 2008) for our revolving credit facility. The principal of our outstanding senior notes ($357,500,000) bears a fixed interest rate of 8 3/8 percent.
(2) Excludes physical and financial purchases of natural gas, NGLs, and other commodities due to the nature of both the price and volume components of such purchases, which vary on a daily or monthly basis. Additionally, we do not have contractual commitments for fixed price and/or fixed quantities of any material amount.
(3) Excludes deferred tax liabilities of $8,274,000 as the amount payable by period can not be reliably estimated in light of future business plans for the entity that generates the deferred tax liability.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk. We are a net seller of NGLs, condensate, sulfur and natural gas. As such, our financial results are exposed to fluctuations in commodity pricing. We have executed swap contracts settled against crude oil, ethane, propane, normal butane, iso butane, and natural gasoline. We have hedged our expected exposure to declines in prices for NGLs and condensate volumes produced for our account in the approximate percentages set forth below:

	2008	2009	2010
NGL	94%	88%	31%
Condensate	72%	70%	71%

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

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

In May 2008, the Partnership entered into one-year commodity swaps to hedge its 2010 NGL commodity risk, except for ethane, which are accounted for using mark-to-market accounting. We chose to delay hedging our 2010 exposure to ethane due to our perception that the prices offered by the counterparties were sharply discounted from comparable forward crude prices. We expect pricing to improve as the period of exposure approaches and intend to execute hedges at such time.

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

On February 29, 2008, the Partnership entered into two-year interest rate swaps related to $300,000,000 of borrowings under its revolving credit facility, effectively locking the base rate for these borrowings at 2.4 percent, plus the applicable margin (2 percent as of September 30, 2008). These interest rate swaps were designated as cash flow hedges on March 7, 2008.

The following table sets forth certain information regarding our NGL, West Texas Intermediate Crude and interest rate swaps outstanding at September 30, 2008. The relevant index price for NGL commodities that we pay is the monthly average of the daily closing price for deliveries into Mont Belvieu, Texas as reported by the Oil Price Information Service (OPIS).

Period	Underlying	Notional Volume/Amount		We Pay	We Receive			Fair Value Asset/(Liability) (in thousands)	
October 2008-December 2009	Ethane	888	(MBbls)	Index	$	0.58-$0.80	($/gallon)	$	4,198
	Propane	816	(MBbls)	Index	$	0.93-$1.5325	($/gallon)		(4,311)

October 2008-December 2010									
January 2009-December 2010	Iso Butane		157	(MBbls)	Index	$	1.685-$1.915	($/gallon)	1,323
October 2008-December 2010	Normal Butane		379	(MBbls)	Index	$	1.12-$1.895	($/gallon)	(2,944)
October 2008-December 2010	Natural Gasoline		351	(MBbls)	Index	$	1.41-$2.53	($/gallon)	(2,801)
October 2008-December 2010	West Texas Intermediate Crude		534	(MBbls)	Index	$	68.17-$121.30	($/Bbl)	(6,102)
October 2008-March 2010	Interest Rate	$	300,000,000		2.40 %		One-month LIBOR		3,275
Credit risk adjustment									1,110
								Total Fair Value $	(6,252)

Item 4. Controls and Procedures

Disclosure controls. At the end of the period covered by this report, an evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, of the effectiveness of the design and operation of our disclosure controls and procedures (as such 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 general partner, concluded that our disclosure controls and procedures were effective as of September 30, 2008 to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is properly recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

Internal control over financial reporting. There have been no changes in the Partnership's internal controls over financial reporting that have materially affected, or are reasonably likely to affect, the Partnership's internal controls over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

The information required for this item is provided in Note 7, Commitments and Contingencies, included in the notes to the unaudited condensed consolidated financial statements included under Part I, Item 1, which information is incorporated by reference into this item.

Item 1A. Risk Factors

In addition to other information set forth in this report, you should carefully consider the factors discussed in part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2007 and part II, "Item 1A. Risk Factors" in our Quarterly Report on Form 10-Q for the three months ended June 30, 2008 which materially affect our business, financial condition or future results. The risks described in this report and in our Annual Report on Form 10-K are not the only risks facing our Partnership.

Part of our business strategy involves expanding our RIGS pipeline system in the Haynesville Shale in North Louisiana, which is a new and emerging natural gas play with limited drilling and production history and subject to more uncertainties than more established formations. If producers are unable to successfully execute their planned drilling programs in the Haynesville Shale, our Haynesville Expansion Project may not be successful.

The success of our Haynesville Expansion Project is subject to successful exploration and development of the Haynesville Shale, a new and emerging natural gas play. The results of producers' exploratory drilling in new or emerging plays, such as the Haynesville Shale, are more uncertain than drilling results in areas that are developed and have established production. Since the Haynesville Shale has limited production history, past drilling results in this area will not necessarily predict future drilling results in the area. In addition, producers in the area have decreased their activity levels in the area due to the current deterioration in the credit markets or the recent declines in the price for natural gas. To the extent producers in the area are unable to execute their expected drilling programs, the return on our investment from this project may not be as attractive as we anticipate. In addition, to the extent we are unable to execute or complete the Haynesville Expansion Project, because of capital constraints, or otherwise, the return on our investment in this area may not be as attractive as we anticipate and our common unit price may decrease.

If we are unable to fully contract for transportation capacity on our Haynesville Expansion Project, our business and our operating results could be adversely affected.

If we are unable to negotiate definitive firm transportation agreements with producers for capacity on our Haynesville Expansion Project, we will not construct the project and this could have an adverse affect on our business and our operating results. Additionally, if we are unable to contract for the remaining incremental transportation capacity, our business and our operating results could be adversely affected.

We may have difficulty financing our planned capital expenditures, which could adversely affect our results and growth.

We have experienced, and expect to continue to experience, substantial capital expenditure and working capital needs, particularly as a result of our Haynesville Expansion Project. At September 30, 2008, the Partnership has purchase obligations totaling $428,454,000, of which $148,924,000 is related to the purchase of major compression components unrelated to the Haynesville Expansion Project, that extend until the year ending December 31, 2010 and $279,530,000 of which is related to the Haynesville Expansion Project that extend until the year ending December 31, 2009. Although we are in discussions with suppliers and vendors to reduce these commitments, our capital expenditures for 2008 and 2009 are expected to exceed substantially the net cash generated by our operations. In addition to using borrowings under our revolving credit facility, we will need to raise additional financing from future equity or debt offerings to fund all of our budgeted capital expenditures for 2009.

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

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

In addition, because of the recent downturn in the financial markets, including the issues surrounding the solvency of many institutional lenders and the recent failure of several banks, our ability to obtain capital from our credit facility may be impaired. For example, as a result of Lehman Brothers Holding, Inc., or Lehman, filing a petition under Chapter 11 of the U.S. Bankruptcy Code, a subsidiary of Lehman that is a committed lender under our credit facility has declined requests to honor its commitment to lend up to $35,000,000 under our credit facility. To date, we have borrowed $25,871,000 from Lehman, thereby effectively reducing the amount available to us under our credit facility to $890,871,000. Upon the repayment of all of our existing outstanding borrowings, the amount available to us under our credit facility will be effectively reduced to $865,000,000. We may be unable to utilize the full borrowing capacity under our credit facility if other lenders are not willing to provide additional funding to make up the portion of the credit facility commitments that Lehman's subsidiary has refused to fund or if any of the remaining committed lenders is unable or unwilling to fund their respective portion of any funding request we make under our credit facility.

Although we obtained commitment letters for approximately $600,000,000 of debt financing for our Haynesville Expansion Project, these commitment letters were subject to the execution of definitive loan documentation and other terms and closing conditions. Given the recent disruption in the credit markets, we believe we will not be able to access these commitments. We are seeking alternative financing sources, which could delay the execution of our Haynesville Expansion Project and or have an adverse affect on our financing terms. Additionally, we intend to finance the remaining costs of the project by using available capacity under our revolving credit agreement and with proceeds from the future issuance of equity. Given that the expansion project will involve the addition of a significant amount of indebtedness and the project will not be operational for an extended period of time, we could be subject to downgrades or being placed on negative watch by the credit rating agencies before the Haynesville Expansion Project results in positive cash flows. Any such downgrade or negative watch could have an adverse effect on our ability to obtain financing or increase the cost of such financing. If we are not able to borrow sufficient amounts under our revolving credit facility and/or are unable to raise sufficient capital to fund our capital expenditures, we may be required to curtail our expansion activities. Any such curtailment could have a material adverse effect on our results and on our future operations.

We may not be able to manage growth relating to our Haynesville Expansion Project effectively, which could decrease our cash flow and adversely affect our results of operation.
Our ability to grow successfully through our Haynesville Expansion Project will depend on a number of factors, some of which will be beyond our control. In general, the construction of additions to or modifications of our existing systems, and the construction of any other new midstream assets involve numerous regulatory, environmental, political and legal uncertainties beyond our control. Our Haynesville Expansion Project may not be completed at budgeted cost, on schedule or at all. Construction may occur over an extended period, and we are not likely to receive a material increase in revenues related to the Haynesville Expansion 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 is intended to capture does not materialize, our estimates of the growth in production prove inaccurate or for other reasons. For any of these reasons, our Haynesville Expansion Project may not generate our expected investment return and that, in turn, could adversely affect our cash flows and results of operations.

In addition, we will be required to obtain new rights-of-way in connection with the Haynesville Expansion Project. We may be unable to obtain such rights-of-way to capitalize on this project. If the cost of obtaining new rights-of-way increases, then our cash flows from this project 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 processing and transportation pipeline systems are dependent on the level of production from natural gas wells that supply our systems and from which production will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. In order to maintain or increase through-put volume levels on our gathering and transportation pipeline systems and the asset utilization rates at our natural gas processing plants, we must continually obtain new supplies. The primary factors affecting our ability to obtain new supplies of natural gas and attract new customers to our assets are: the level of successful drilling activity near our systems and our ability to compete with other gathering and processing companies for volumes from successful new wells.

The level of natural gas drilling activity is dependent on economic and business factors beyond our control. The primary factor that impacts drilling decisions is natural gas prices. A sustained decline in natural gas prices could result in a decrease in exploration and development activities in the fields served by our gathering and processing facilities and pipeline transportation systems, which would lead to reduced utilization of these assets. In addition, producers may decrease their activity levels due to the current deterioration in the credit markets. The recent decline in the credit markets and the availability of credit and the lack of availability of debt or equity financing or the recent declines in natural gas prices may result in a significant reduction in producers’ exploratory drilling. 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, through-put volumes on our pipelines and the utilization rates of our processing facilities would decline, which could have a material adverse effect on our business, results of operations and financial condition.

Our natural gas contract compression operations significantly depend upon the continued demand for and production of natural gas and crude oil. Demand may be affected by, among other factors, natural gas prices, crude oil prices, weather, demand for energy, and availability of alternative energy sources. Any prolonged, substantial reduction in the demand for natural gas or crude oil would, in all likelihood, depress the level of production activity and result in a decline in the demand for our contract compression services and products. Lower natural gas prices or crude oil prices over the long-term could result in a decline in the production of natural gas or crude oil, respectively, resulting in reduced demand for our natural gas contract compression services. Additionally, production from natural gas sources such as longer-lived tight sands, shales and coalbeds constitute an increasing percentage of our compression services business. Such sources are generally less economically feasible to produce in lower natural gas price environments, and a reduction in demand for natural gas or natural gas lift for crude oil may cause such sources of natural gas to be uneconomic to drill and produce, which could in turn negatively impact the demand for our services.

Natural gas, NGLs and other commodity prices are volatile, and a reduction in these prices could adversely affect our cash flow and operating results.
We are subject to risks due to frequent and often substantial fluctuations in commodity prices. 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. Recently, oil and natural gas prices have been extremely volatile and have declined substantially. On November 7, 2008, the price of oil on the New York Mercantile Exchange fell to $60.35 per barrel for December 2008 delivery, declining to a 17-month low and from a high of $147.27 per barrel in July 2008. Volatility in oil and natural gas prices can impact our customers' activity levels and spending for our products and services, as well as our margins under our keep-whole and percentage-of proceeds natural gas gathering and processing contracts.

The markets and prices for natural gas and NGLs depend upon factors beyond our control. These factors include demand for oil, natural gas and NGLs, which fluctuates with changes in market and economic conditions and other factors, including:

- the 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 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.

We are exposed to the credit risks of our key customers, and any material nonpayment or nonperformance by our key customers could adversely affect our cash flow and results of operations.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. Any material nonpayment or nonperformance by our key customers could reduce our ability to make distributions to our unitholders. Many of our customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. Recently, there has been a significant decline in the credit markets and the availability of credit. Additionally, many of our customers' equity values have substantially declined. The combination of reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under reserve based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction in our customers' liquidity and ability to make payment or perform on their obligations to us. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us.

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

The interest rate on our senior notes is fixed and the loans outstanding under our credit facility bear interest at a floating rate. In addition, 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 in order to make acquisitions, to reduce debt or for other purposes.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The information required for this item is provided in Note 1, Organization and Summary of Significant Accounting Policies, Note 3, Acquisitions, and Note 6, Equity Offering included in the notes to the unaudited condensed consolidated financial statements included under Part I, Item 1, which information is incorporated by reference into this item.

Item 6. Exhibits

The exhibits below are filed as a part of this report:

Exhibit 10.1 – Employment Agreement with Randall Dean
Exhibit 12.1 – Computation of Ratio of Earnings to Fixed Charges
Exhibit 31.1 – Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer
Exhibit 31.2 – Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer
Exhibit 32.1 – Section 1350 Certifications of Chief Executive Officer
Exhibit 32.2 – Section 1350 Certifications of Chief Financial Officer

SIGNATURE

Pursuant to the requirements 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

November 9, 2008

/s/ Lawrence B. Connors
Lawrence B. Connors
Senior Vice President, Finance and Chief Accounting Officer (Duly Authorized Officer)