Regency Energy Partners LP
Form 10-Q/A
May 14, 2009

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

FORM 10-Q/A
(Amendment No. 2)

(Mark One)
þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2009

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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). o 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 the definitions of "large accelerated filer, accelerated filer and small reporting company" in Rule 12b-2 of the Exchange Act.

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

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 81,187,728 common units outstanding as of April 30, 2009.

REGENCY ENERGY PARTNERS LP EXPLANATORY NOTE

The purpose of this Amendment No. 2 to Regency Energy Partners LP's quarterly report on Form 10-Q for the quarter ended March 31, 2009 is to correct information provided with respect to the guarantors of the 8 3/8 percent Senior Notes due 2013. Please see Note 6 to the Unaudited Condensed Consolidated Financial Statements. This amendment also corrects notional volumes for hedged commodities disclosed in Item 3.

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. 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
Alinda	Alinda Capital Partners LLC, a Delaware limited liability company that is an independent private investment firm specializing in infrastructure investments
Alinda Investor I	Alinda Gas Pipelines I, L.P., a Delaware limited partnership
Alinda Investor II	Alinda Gas Pipelines II, L.P., a Delaware limited partnership
Alinda Investors	Alinda Investor I and Alinda Investor II, collectively
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
EITF	Emerging Issues Task Force
El Paso	El Paso Field Services, LP
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FSP	Financial Accounting Standards Board Statement of Position
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 LLP, the general partner of Regency GP LP, which effectively manages the business and affairs of the Partnership
HPC	RIGS Haynesville Partnership Co., a general partnership that owns 100 percent of RIGS
Lehman	Lehman Brothers Holdings, Inc.
LIBOR	London Interbank Offered Rate
LTIP	Long-Term Incentive Plan
MMbtu	One million BTUs
MMbtu/d	One million BTUs per day
MMcf	One million cubic feet
MMcf/d	One million cubic feet per day
NOE	Notice of Enforcement
NGLs	Natural gas liquids
Nasdaq	Nasdaq Stock Market, LLC
NYMEX	New York Mercantile Exchange
Partnership	Regency Energy Partners LP
RGS	Regency Gas Services LP
RIGS	Regency Intrastate Gas LP
Regency HIG	Regency Haynesville Intrastate Gas LLC, a wholly owned subsidiary of the Partnership
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

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 expre 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:

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

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

Other factors that could cause our actual results to differ from our projected results are discussed in Item 1A of our December 31, 2008 annual report.

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

Item 1. Financial Statements

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

	March 31, 2009 (unaudited)	December 31, 2008
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 6,578	$ 599
Trade accounts receivable, net of allowance of $1,073 and $941	35,349	40,875
Accrued revenues	70,200	96,712
Related party receivables	4,998	855
Assets from risk management activities	67,020	73,993
Other current assets	7,911	23,369
Total current assets	192,056	236,403
Property, Plant and Equipment:		
Gathering and transmission systems	449,971	652,267
Compression equipment	805,873	799,527
Gas plants and buildings	154,553	156,246
Other property, plant and equipment	152,089	167,256
Construction-in-progress	92,462	154,852
Total property, plant and equipment	1,654,948	1,930,148
Less accumulated depreciation	(204,256)	(226,594)
Property, plant and equipment, net	1,450,692	1,703,554
Other Assets:		
Investment in unconsolidated subsidiary	400,336	-
Long-term assets from risk management activities	26,944	36,798
Other, net of accumulated amortization of debt issuance costs of $6,292 and $5,246	17,723	13,880
Total other assets	445,003	50,678
Intangible Assets and Goodwill:		
Intangible assets, net of accumulated amortization of $24,659 and $22,517	199,564	205,646
Goodwill	228,114	262,358
Total intangible assets and goodwill	427,678	468,004
TOTAL ASSETS	$ 2,515,429	$ 2,458,639
LIABILITIES & PARTNERS' CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Trade accounts payable	$ 44,151	$ 65,483
Accrued cost of gas and liquids	53,133	76,599
Related party payables	247	-
	11,498	11,572

Deferred revenue, including related party amounts of $22 and $0				
Liabilities from risk management activities		31,729		42,691
Other current liabilities		19,583		20,605
Total current liabilities		160,341		216,950
Long-term liabilities from risk management activities		-		560
Other long-term liabilities		15,247		15,487
Long-term debt		1,133,233		1,126,229
Commitments and contingencies				
Partners' Capital and Noncontrolling Interest:				
Common units (81,786,730 and 55,519,903 units authorized; 81,187,728 and 54,796,701 units issued and outstanding at March 31, 2009 and December 31, 2008)		1,108,752		764,161
Class D common units (7,276,506 units authorized, issued and outstanding at December 31, 2008)		-		226,759
Subordinated units (19,103,896 units authorized, issued and outstanding at December 31, 2008)		-		(1,391)
General partner interest		25,495		29,283
Accumulated other comprehensive income		58,570		67,440
Noncontrolling interest		13,791		13,161
Total partners' capital and noncontrolling interest		1,206,608		1,099,413
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$	2,515,429	$	2,458,639

See accompanying notes to condensed consolidated financial statements

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

	Three Months Ended March 31, 2009		2008	
REVENUES				
Gas sales	$	148,270	$	236,692
NGL sales		49,585		108,499
Gathering, transportation and other fees, including related party amounts of $811 and $991		72,621		61,986
Net realized and unrealized gain (loss) from risk management activities		14,455		(13,657)
Other		5,194		11,715
Total revenues		290,125		405,235
OPERATING COSTS AND EXPENSES				
Cost of sales, including related party amounts of $247 and $403		182,901		313,589
Operation and maintenance		36,042		28,845
General and administrative		14,852		11,271
Gain on asset sales, net		(133,932)		-
Management services termination fee		-		3,888
Depreciation and amortization		27,889		21,741
Total operating costs and expenses		127,752		379,334
OPERATING INCOME		162,373		25,901
Income from unconsolidated subsidiary		336		-
Interest expense, net		(14,227)		(15,406)
Other income and deductions, net		42		176
INCOME BEFORE INCOME TAXES		148,524		10,671
Income tax expense		100		251
NET INCOME	$	148,424	$	10,420
Net income attributable to noncontrolling interest		(35)		(72)
NET INCOME ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$	148,389	$	10,348
General partner's interest, including IDR		3,533		776
Net income allocated to non-vested units		1,354		95
Beneficial conversion feature for Class D common units		820		1,559
Limited partners' interest	$	142,682	$	7,918
Basic and Diluted earnings per unit:				
Amount allocated to common and subordinated units	$	142,682	$	7,918
		77,271,886		59,229,507

Weighted average number of common and subordinated units outstanding				
Basic income per common and subordinated unit	$	1.85	$	0.13
Diluted income per common and subordinated unit	$	1.78	$	0.13
Distributions per unit	$	0.445	$	0.40
Amount allocated to Class D common units	$	820	$	1,559
Total number of Class D common units outstanding		7,276,506		7,276,506
Income per Class D common unit due to beneficial conversion feature	$	0.11	$	0.21
Distributions per unit	$	-	$	-
Amount allocated to Class E common units	$	-	$	-
Total number of Class E common units outstanding		-		4,701,034
Income per Class E common unit	$	-	$	-
Distributions per unit	$	-	$	-

See accompanying notes to condensed consolidated financial statements

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

	Three Months Ended March 31, 2009	2008
Net income	$ 148,424	$ 10,420
Net hedging amounts reclassified to earnings	(14,250)	10,435
Net change in fair value of cash flow hedges	5,380	(2,834)
Comprehensive income	139,554	18,021
Comprehensive income attributable to noncontrolling interest	(35)	(72)
Comprehensive income attributable to Regency Energy Partners LP	$ 139,519	$ 17,949

See accompanying notes to condensed consolidated financial statements

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

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
OPERATING ACTIVITIES		
Net income	$ 148,424	$ 10,420
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization, including debt issuance cost amortization	28,932	22,398
Income from unconsolidated subsidiary	(336)	-
Risk management portfolio valuation changes	(3,565)	3,098
Gain on asset sales, net	(133,932)	-
Unit based compensation expenses	1,189	794
Cash flow changes in current assets and liabilities:		
Trade accounts receivable, accrued revenues, and related party receivables	22,741	(19,264)
Other current assets	10,458	2,800
Trade accounts payable, accrued cost of gas and liquids, and related party payables	(36,948)	25,950
Other current liabilities	(1,022)	18,249
Other assets and liabilities	390	(6,907)
Net cash flows provided by operating activities	36,331	57,538
INVESTING ACTIVITIES		
Capital expenditures	(80,255)	(97,896)
Acquisitions	-	(574,059)
Proceeds from asset sales	83,097	-
Net cash flows provided by (used in) investing activities	2,842	(671,955)
FINANCING ACTIVITIES		
Net borrowings under revolving credit facilities	7,004	609,000
Partner contributions	-	7,663
Partner distributions	(34,143)	(24,341)
Debt issuance costs	(6,055)	-
Net cash flows provided by (used in) financing activities	(33,194)	592,322
Net increase (decrease) in cash and cash equivalents	5,979	(22,095)
Cash and cash equivalents at beginning of period	599	32,971
Cash and cash equivalents at end of period	$ 6,578	$ 10,876
Supplemental cash flow information:		
Interest paid, net of amounts capitalized	$ 5,502	$ 5,047

Non-cash capital expenditures in accounts payable	18,241	18,517
Issuance of common units for an acquisition	-	219,590
Contribution of fixed assets, goodwill and working capital to RIGS Haynesville Partnership Co.	266,024	-

See accompanying notes to condensed consolidated financial statements

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

Regency Energy Partners LP

	Units									
	Common	Class D	Subordinated	Common	Class D	Subordinated	General Partner Interest	Accumulated Other Comprehensive Income	Noncontrolling Interest	Total
Balance - December 31, 2008	54,796,701	7,276,506	19,103,896	$ 764,161	$ 226,759	$ (1,391)	$ 29,283	$ 67,440	$ 13,161	$ 1,099,413
Revision of partner interest	-	-	-	6,073	-	-	(6,073)	-	-	-
Issuance of restricted common units, net of forfeitures	10,625	-	-	-	-	-	-	-	-	-
Conversion of subordinated units	19,103,896	-	(19,103,896)	(1,391)	-	1,391	-	-	-	-
Unit based compensation expenses	-	-	-	1,189	-	-	-	-	-	1,189
Partner distributions	-	-	-	(32,895)	-	-	(1,248)	-	-	(34,143)
Net income	-	-	-	144,036	820	-	3,533	-	35	148,424
Conversion of Class D common units	7,276,506	(7,276,506)	-	227,579	(227,579)	-	-	-	-	-
Contributions from noncontrolling interest	-	-	-	-	-	-	-	-	595	595
Net hedging amounts reclassified to earnings	-	-	-	-	-	-	-	(14,250)	-	(14,250)
Net change in fair value of cash flow hedges	-	-	-	-	-	-	-	5,380	-	5,380
Balance - March 31, 2009	81,187,728	-	-	$ 1,108,752	$ -	$ -	$ 25,495	$ 58,570	$ 13,791	$ 1,206,608

See accompanying notes to condensed consolidated financial statements

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Regency Energy Partners LP
Notes to Unaudited Condensed Consolidated Financial Statements

1. Organization and Summary of Significant Accounting Policies
Organization. The unaudited condensed consolidated financial statements presented herein contain the results of Regency Energy Partners LP and its wholly owned subsidiaries. The Partnership and its subsidiaries are engaged in the business of gathering, processing, contract compression, transporting, and marketing natural gas and NGLs.

The unaudited financial information as of, and for the three months ended March 31, 2009 has been prepared on the same basis as the audited consolidated financial statements included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2008. 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.

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

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

	Permits and Licenses	Customer Contracts	Trade Names	Customer Relations	Total
			(in thousands)		
Balance at December 31, 2008	$ 8,582	$ 126,799	$ 32,848	$ 37,417	$ 205,646
Disposals	(2,932)	-	-	-	(2,932)
Amortization	(174)	(1,807)	(585)	(584)	(3,150)
Balance at March 31, 2009	$ 5,476	$ 124,992	$ 32,263	$ 36,833	$ 199,564

The weighted average amortization period for permits and licenses, customer contracts, trade names, and customer relations are 15, 24, 15, and 19 years, respectively. Permits and licenses are generally renewed with minimal expense as a charge to operating and maintenance expense in the period incurred. Regarding customer contracts, the actual remaining life of the contracts were used to evaluate the cash flows expected with no renewal assumption. The trade name and customer relations intangible assets use the going concern assumption with no renewal cost. The expected amortization of the intangible assets for each of the five succeeding years is as follows.

Year ending December 31,	Total (in thousands)
2009 (remaining)	$ 9,064
2010	12,086
2011	10,828
2012	10,535
2013	10,535

Revision to Partners' Capital Accounts. In 2009, the Partnership revised the allocation of net income between the general partner and common unit holders from a previous period to reflect the income allocation provisions of the Partnership agreement. The effect of this revision is not material to the prior financial statements.

Recently Issued Accounting Standards. In December 2007, the FASB issued SFAS No. 141(R), “Business Combinations” (“SFAS 141(R)”), which significantly changes the accounting for business acquisitions both during the period of the acquisition and in subsequent periods. The Partnership adopted SFAS 141(R) on January 1, 2009.

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 significantly changes the accounting and reporting related to noncontrolling interests in a consolidated subsidiary. The Partnership adopted SFAS No. 160 for all periods presented. This statement requires the recognition of a noncontrolling interest (formerly styled as a minority interest) in partners’ capital in the consolidated financial statements and separate from the partners’ interest. Also, the amount of net income attributable to the noncontrolling interest is included in the consolidated net income on the face of the income statement.

In March 2008, the FASB issued EITF 07-4, "Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships" ("EITF 07-4"). EITF 07-4 defines how to allocate net income among the various classes of equity, including incentive distribution rights (or "IDRs"), narrowing the number of currently acceptable methods. The standard became effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application was not permitted, and EITF 07-4 must be applied retrospectively for all financial statements presented. The adoption of this standard changes the Partnership's method of allocating net income to holders of the IDRs in periods where net income exceeds cash distributed. Because the Partnership Agreement restricts the amount of distributions to holders of IDRs based on cash available for distribution, undistributed net income will be allocated based on the ownership interests of the general partner and unitholders. Further, because the IDR's are deemed to have no ownership interest , no undistributed net income will be allocated to this class of security. All prior period earnings per unit data have been adjusted.

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

In May 2008, the FASB issued SFAS No. 162, "The Hierarchy of Generally Accepted Accounting Principles" ("SFAS 162"), which identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements that are presented in conformity of GAAP. SFAS 162's effective date is November 15, 2008. The adoption of SFAS 162 did not 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") and is effective for fiscal years beginning after December 15, 2008. The adoption of this standard was applied retrospectively and had an imaterial impact on the Partnership's earnings per unit.

2. Income per Limited Partner Unit

The Partnership issued 7,276,506 Class D common units in connection with the CDM acquisition. 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 Class D common units converted to common units on a one-for-one basis on February 9, 2009.

The following table provides a reconciliation of the basic and diluted earnings per unit computations.

	For the Three Months Ended March 31, 2009			For the Three Months Ended March 31, 2008		
	Income	Units	Per-Unit Amount	Income	Units	Per-Unit Amount
	(in thousands except unit and per unit data)					
Basic Earnings per Unit						
	$ 142,682	77,271,886	$ 1.85	$ 7,918	59,229,507	$ 0.13

Limited Partners' interest in net income						
Effect of Dilutive Securities						
Common unit options	-	-		-	207,817	
Class D common units	820	3,234,003		1,559	7,276,506	
Class E common units	-	-		-	4,701,034	
Diluted Earnings per Unit	$ 143,502	80,505,889	$ 1.78	$ 9,477	71,414,864	$ 0.13

The following table shows securities that could potentially dilute earnings per unit in the future that were not included in the computation of diluted earnings per unit because to do so would have been antidilutive.

	Three Months Ended	
	March 31, 2009	March 31, 2008
Common unit options	328,618	-
Restricted common units	699,175	555,000

3. Disposition

On March 17, 2009, the Partnership announced the completion of the transactions contemplated by the Contribution Agreement (the "Contribution Agreement") relating to a new joint venture arrangement among Regency HIG, GECC and the Alinda Investors. The Partnership contributed to HPC RIGS, which owns the Regency Intrastate Gas System, valued at $400,000,000, in exchange for a 38 percent general partnership interest in HPC. GECC and the Alinda Investors contributed $126,500,000 and $526,500,000 in cash, respectively, to HPC in return for a 12 percent and a 50 percent general partnership interest, respectively. In accordance with SFAS No. 160, the disposition and deconsolidation resulted in the recording of a $133,940,000 gain (of which $52,857,000 represents the remeasurement of the Partnership retained 38 percent interest to its fair value), net of transaction costs of $5,158,000.

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

	Pro Forma Results for the Three Months Ended			
	March 31, 2009		March 31, 2008	
	(in thousands except unit and per unit data)			
Revenue	$	277,796	$	398,950
Net income attributable to Regency Energy Partners LP	$	10,970	$	145,803
Less:				
General partner's interest, including IDR		785		2,920
Non-vested common unit holders' interest		90		1,404
Beneficial conversion feature for Class D common units		820		1,559
Limited partners' interest in net income	$	9,275	$	139,919
Basic and Diluted earnings per unit:				
Amount allocated to common and subordinated units	$	9,275	$	139,919
Weighted average number of common and subordinated units outstanding		77,271,886		59,229,507
Basic income per common and subordinated unit	$	0.12	$	2.36
Diluted income per common and subordinated unit	$	0.12	$	2.01
Distributions per unit	$	0.445	$	0.40
Amount allocated to Class D common units	$	820	$	1,559
Total number of Class D common units outstanding		7,276,506		7,276,506
Basic and diluted income per Class D common unit due to beneficial conversion feature	$	0.11	$	0.21
Distributions per unit	$	-	$	-
Amount allocated to Class E common units	$	-	$	-
Weighted average number of Class E common units outstanding		-		4,701,034
Basic and diluted income per Class E common unit	$	-	$	-
Distributions per unit	$	-	$	-

4. Investment in Unconsolidated Subsidiary

As described in the Disposition footnote, the Partnership contributed RIGS to HPC for a 38 percent general partner interest in HPC. The summarized financial information of HPC as of March 31, 2009 and for the period from inception (March 18, 2009) to March 31, 2009 is disclosed below in accordance with Rule 4-08 of Regulation S-X. The Partnership recognized $336,000 in investing income from unconsolidated subsidiary for its 38 percent ownership interest from inception (March 18, 2009) to March 31, 2009.

Condensed Consolidated Balance Sheet
March 31, 2009
Unaudited
(in thousands)

ASSETS		
Total current assets	$	537,178
Property, plant and equipment, net		481,143
Total other assets		61,564
TOTAL ASSETS	$	1,079,885
LIABILITIES & PARTNERS' CAPITAL		
Total current liabilities	$	26,001
Partners' capital		1,053,884
TOTAL LIABILITIES & PARTNERS' CAPITAL	$	1,079,885

Condensed Consolidated Income Statement
From Inception (March 18, 2009) to March 31, 2009
Unaudited
(in thousands)

Total revenues	$	1,826
Total operating costs and expenses, including depreciation expense of $669		1,046
OPERATING INCOME		780
Other income and deductions, net		104
NET INCOME	$	884

5. Risk Management Activities

In March 2008, the FASB issued SFAS No. 161, “Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133” (“SFAS 161”). SFAS 161 requires enhanced disclosures about derivative and hedging activities. The Partnership adopted this standard as of January 1, 2009 and its adoption had no impact on the results of operations or cash flows.

Risk and Accounting Policies. The Partnership is exposed to market risks associated with commodity prices, counterparty credit, and interest rates. The Partnership established comprehensive risk management policies and procedures to monitor and manage these market risks. The Partnership’s General Partner is responsible for delegation of transaction authority levels, and the Risk Management Committee of the General Partner is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits. The Risk Management Committee receives regular briefings on positions and exposures, credit exposures, and overall risk management in the context of market activities.

The Partnership primarily deals with financial institutions when entering into financial derivatives.

Commodity Price Risk. The Partnership is exposed to the impact of market fluctuations in the prices of natural gas, NGLs, and other commodities as a result of our gathering, processing and marketing activities, and the Partnership is a net seller of natural gas, NGLs and condensate. The Partnership attempts to mitigate commodity price risk exposure by matching pricing terms between its purchases and sales of commodities. To the extent that the Partnership markets commodities in which pricing terms cannot be matched and there is a substantial risk of price exposure, the Partnership attempts to use financial hedges to mitigate the risk. It is the Partnership’s policy not to take any speculative marketing positions. In some cases, the Partnership may not be able to match pricing terms or to cover its risk to price exposure with financial hedges, and it may be exposed to commodity price risk.

Both the Partnership’s profitability and cash flows are affected by volatility in prevailing natural gas and NGL prices. Natural gas and NGL prices are impacted by changes in the supply and demand for NGLs and natural gas, as well as market uncertainty. Adverse effects on cash flows from reductions in natural gas and NGL product prices could adversely affect the Partnership’s ability to make distributions to unitholders. The Partnership manages this commodity price exposure through an integrated strategy that includes management of its contract portfolio, matching sales prices of commodities with purchases, optimization of our portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts.

The Partnership has executed swap contracts settled against condensate, ethane, propane, butane, natural gas, and natural gasoline market prices. The Partnership hedged its expected exposure to declines in prices for natural gas, NGLs and condensate volumes produced for its account in the approximate percentages set for below:

	2009	2010
NGL	97%	36%
Condensate	75	76

Natural gas	83	-

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 dedesignated swaps continued to serve as economic hedges against price exposure for the Partnership. At March 31, 2009, the Partnership has the following commodity hedging programs that qualify as cash flow hedges: the 2009 NGLs, natural gas and West Texas Intermediate crude oil hedging programs and the 2010 West Texas Intermediate crude oil hedging program.

In March 2008, the Partnership entered offsetting trades against its existing 2009 NGL portfolio of mark-to-market hedges, which it believes will substantially reduce the volatility of its 2009 NGL hedges. This group of trades, along with the pre-existing 2009 NGL portfolio, will continue to be accounted for on a mark-to-market basis. Simultaneously, the Partnership executed additional 2009 NGL swaps which were designated under SFAS 133 as cash flow hedges. In May 2008, the Partnership entered into commodity swaps to hedge a portion of its 2010 NGL commodity risk, except for ethane, which do not qualify for cash flow hedging accounting treatment.

The Partnership accounts for a portion of its 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 as a cash flow hedge. In May 2008, the Partnership entered into a West Texas Intermediate crude oil swap to hedge its 2010 condensate price risk, which was designated as a cash flow hedge.

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

Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under our existing credit facility. As of March 31, 2009, we had $475,733,000 of outstanding long-term balances exposed to variable interest rate risk. An increase of 100 basis points in the LIBOR rate would increase our annual payment by $4,757,000. On February 29, 2008, the Partnership entered into two-year interest rate swaps related to $300,000,000 of borrowings under its revolving credit facility, effectively locking the base rate for these borrowings at 2.4 percent, plus the applicable margin (3 percent as of March 31, 2009) through March 5, 2010. These interest rate swaps were designated as cash flow hedges in March 2008.

Credit Risk. The Partnership's purchase and resale of natural gas exposes it to credit risk, as the margin on any sale is generally a very small percentage of the total sales price. Therefore a credit loss can be very large relative to overall profitability. The Partnership attempts to ensure that it issues credit only to credit-worthy counterparties and that in appropriate circumstances any such extension of credit is backed by adequate collateral such as a letter of credit or a parental guarantee.

The Partnership is exposed to credit risk from it derivative counterparties. The Partnership does not require collateral from these counterparties. If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership would experience a loss of $96,213,000 based on commodity forward curve pricing as of March 31, 2009. The Partnership has entered into Master International Swap Dealers Association Agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximium loss of $96,213,000 would be reduced by $27,394,000 due to the netting feature.

Quantitative Disclosures. The Partnership expects to reclassify $49,112,000 of net hedging gains to revenues or interest expense from accumulated other comprehensive income in the next twelve months.

The Partnership's risk management activities assets and liabilities, including its SFAS No. 157, "Fair Value Measurements" ("SFAS 157") credit risk adjustment, are detailed below for the periods ended March 31, 2009 and December 31, 2008.

	Asset Derivatives Fair Value	
	March 31, 2009	December 31, 2008
	(in thousands)	
Derivatives designated as cash flow hedging instruments		
Current assets from risk management activities		
Commodity contracts	$ 53,436	$ 59,882
Long-term assets from risk management activities		
Commodity contracts	10,133	13,373
Total cash flow hedging instruments	63,569	73,255
Derivatives not designated as hedging instruments		
Current assets from risk management activities		
Commodity contracts	15,833	16,001
Long-term assets from risk management activities		
Commodity contracts	16,811	23,425
Total derivatives not designated as hedging instruments	32,644	39,426

SFAS 157 Credit Risk Assessment				
Current assets from risk management activities		(2,249)		(1,890)
Total assets from risk management activities	$	93,964	$	110,791

	Liability Derivatives Fair Value			
	March 31, 2009		December 31, 2008	
	(in thousands)			
Derivatives designated as cash flow hedging instruments				
Current liabilities from risk management activities				
Interest rate contracts	$	4,605	$	4,680
Long-term liabilities from risk management activities				
Interest rate contracts		-		560
Total cash flow hedging instruments		4,605		5,240
Derivatives not designated as hedging instruments				
Current liabilities from risk management activities				
Commodity contracts		27,394		38,402
Total derivatives not designated as hedging instruments		27,394		38,402
SFAS 157 credit risk assessment				
Current liabilities from risk management activities		(270)		(391)
Total liabilities from risk management activities	$	31,729	$	43,251

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The Partnership's statement of operations for the periods ended March 31, 2009 and 2008 were impacted by risk management activities as follows.

Derivatives in Cash Flow Hedging Relationships

	Amount of Gain (Loss) Recognized in OCI on Derivative (Effective Portion)		Location of:	Amount of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)		Amount of Gain (Loss) Recognized in Income on Derivative (Ineffective Portion)	
	March 31, 2009	March 31, 2008		March 31, 2009	March 31, 2008	March 31, 2009	March 31, 2008
			(in thousands)				
Interest rate contracts	$ (838)	$ (421)	Interest expense, net	$ (1,472)	$ 188	$ -	$ -
Commodity contracts	6,218	(2,413)	Net realized and unrealized gain(loss) from risk management activities	16,519	(10,567)	615	223
Total	$ 5,380	$ (2,834)		$ $15,047	$ (10,379)	$ 615	$ 223

Derivatives Not in SFAS 133 Hedging Relationships

	Amount of Loss from Dedesignation Amortized from Accumulated OCI into Income		Amount of Gain (Loss) Recognized in Income on Derivative	
	March 31, 2009	March 31, 2008	March 31, 2009	March 31, 2008
Net realized and unrealized gain (loss) from risk management activities for commodity contracts	$ (797)	$ (56)	$ (1,402)	$ (3,257)

SFAS 157 Credit Risk Assessment for All Derivatives	Location of :	Amount of Gain or (Loss) Recognized in Income on Derivative	
		March 31, 2009	March 31, 2008
Commodity and interest rate swaps	Net realized and unrealized gain/(loss)	$ (480)	$ -

	from risk management activities

6. Long-term Debt

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

	March 31, 2009	December 31, 2008
	(in thousands)	
Senior notes	$ 357,500	$ 357,500
Revolving loans	775,733	768,729
Total	1,133,233	1,126,229
Less: current portion	-	-
Long-term debt	$ 1,133,233	$ 1,126,229
Availability under revolving credit facility:		
Total credit facility limit	$ 900,000	$ 900,000
Unfunded Lehman commitments	(5,578)	(8,646)
Revolving loans	(775,733)	(768,729)
Letters of credit	(16,257)	(16,257)
Total available	$ 102,432	$ 106,368

On March 17, 2009, RGS closed on Amendment No. 7 to its Credit Agreement (the "Amendment"). The Amendment authorized the contribution of RIGS to a joint venture (HPC) and allowed for future investment up to $135,000,000 in a joint venture. The amendment imposed additional financial restrictions that limit the ratio of senior secured indebtedness to EBITDA. The alternate base rate used to calculate interest on base rate loans will be calculated based on the greatest to occur of a base rate, a federal funds effective rate plus 0.50 percent and an adjusted LIBOR rate for a borrowing with a one-month interest period plus 1.50 percent. The applicable margin shall range from 1.50 percent to 2.25 percent for base rate loans, 2.50 percent to 3.25 percent for Eurodollar loans and commitment fees will range from 0.375 percent to 0.500 percent.

GECC Credit Facility. On February 26, 2009, the Partnership entered into a $45,000,000 unsecured revolving credit agreement with GECC. The proceeds of the GECC Credit Facility were available for expenditures made in connection with the Haynesville Expansion Project prior to the effectiveness of the Amendment. The commitments under the Revolving Credit Facility terminated on March 17, 2009. The Partnership paid a commitment fee of $2,718,000 to GECC related to this GECC Credit Facility, which was recorded in gain on asset sales, net.

On September 15, 2008, Lehman filed a petition in the United States Bankruptcy Court seeking relief under chapter 11 of the United States Bankruptcy Code. As of March 31, 2009, the Partnership borrowed all but $5,578,000 of the amount committed by Lehman under the Credit Facility. Lehman has declined requests to honor its remaining commitment, effectively reducing the total size of the Credit Facility's capacity to $894,422,000. Further, if the Partnership makes repayments of loans against the revolving facility which were, in part, funded by Lehman, the amounts funded by Lehman may not be reborrowed.

The outstanding balance of revolving debt under the credit facility bears interest at LIBOR plus a margin or Alternate Base Rate (equivalent to the U.S prime rate lending rate) plus a margin or a combination of both. The 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 5.19 percent and 6.90 percent for the three months ended March 31, 2009 and 2008, respectively. The senior notes bear interest at a fixed rate of 8.375 percent.

Finance Corp. does not have any operations of any kind and will not have any revenue other than as may be incidental as a co-issuer of the Senior Notes. The Partnership has no independent operations, the guarantees are full and unconditional and joint and several, and there are no subsidiaries of the Partnership other than Finance Corp. that do not guarantee the Senior Notes. In accordance with Rule 3-10 of Regulation S-X, the Partnership has not included condensed consolidated financial information of guarantors of the Senior Notes.

7. Commitments and Contingencies

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

Escrow Payable. At March 31, 2009, $1,510,000 remained in escrow pending the completion by El Paso of environmental remediation projects pursuant to the purchase and sale agreement ("El Paso PSA") related to assets in north Louisiana and the mid-continent area. In the El Paso PSA, El Paso indemnified the predecessor of our operating partnership, RGS, against losses arising from pre-closing and known environmental liabilities subject to a limit of $84,000,000 and certain deductible limits. Upon completion of a Phase II environmental study, the Partnership notified El Paso of remediation obligations amounting to $1,800,000 with respect to known environmental matters and $3,600,000 with respect to pre-closing environmental liabilities. This escrow amount will be further reduced under a specified schedule as El Paso completes its cleanup obligations and the remainder will be released upon completion.

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

Contingent Purchase of Sonat Assets. In March of 2008, the Partnership, through the Nexus Acquisition, obtained the rights to a contingent commitment to purchase 136 miles of pipeline that could facilitate the Nexus' system integration into the Partnership's north Louisiana asset base. The purchase commitment was 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. 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. On March 19, 2009, FERC denied the Sonat abandonment application and this obligation has been terminated.

TCEQ Notice of Enforcement. On February 15, 2008, the TCEQ issued a NOE concerning one of the Partnership's processing plants located in McMullen County, Texas (the "Plant"). The NOE alleges that, between March 9, 2006, and May 8, 2007, the Plant experienced 15 emission events of various durations from four hours to 41 days, which were not reported to TCEQ and other agencies within 24 hours of occurrence. On April 3, 2008, TCEQ presented the Partnership with a written offer to settle the allegation in the NOE in exchange for payment of an administrative penalty of $480,000, and it later reduced its settlement demand to $360,000 in July 2008. The Partnership was unable to settle this matter on a satisfactory basis and the TCEQ has referred the matter to its litigation division for further administrative proceedings.

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

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

8. Related Party Transactions
The employees operating the assets of the Partnership and its subsidiaries and all those providing staff or support services are employees of the General Partner. Pursuant to the Partnership Agreement, our General Partner receives a monthly reimbursement for all direct and indirect expenses incurred on behalf of the Partnership. Reimbursements of $7,808,000, and $6,888,000 were recorded in the Partnership's financial statements during the three months ended March 31, 2009 and 2008, 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 certain members of management received cash distributions of $9,578,000 and $390,000, respectively during the three months ended March 31, 2009.

The Partnership's contract compression segment provides contract compression services to CDM MAX, LLC and HPC. At March 31, 2009, the Partnership has a $398,000 receivable related to CDM MAX, LLC and a $59,000 receivable related to HPC.

Under a Master Services Agreement with HPC, the Partnership operates and provides all employees and services for the operation and management of the joint venture. Under this agreement the Partnership will receive $500,000 monthly as a management fee. In the three months ended March 31, 2009, the Partnership received a partial month management fee of $226,000. At March 31, 2009, the Partnership has $4,354,000 in receivables from HPC.

At March 31, 2009, the Partnership had a receivable of $187,000 from GE EFS.

9. Segment Information
With the completion of the Contribution Agreement, the Partnership's management realigned the composition of its segments. Accordingly, the Partnership has restated the items of segment information for earlier periods to reflect this new alignment.

The Partnership has three principal 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 Partnership, through its producer services function, primarily purchases natural gas from producers at gathering systems and plants connected to its pipeline systems and sells this gas at downstream outlets.

Following the contribution of RIGS to HPC, the transportation segment consists exclusively of the Partnership's 38 percent interest in HPC, for which equity method accounting applies. Prior periods have been restated to reflect the Partnership's wholly owned subsidiary of Regency Intrastate Gas Pipeline as the exclusive reporting unit within this segment. The transportation segment uses pipelines to transport natural gas from receipt points on its system to interconnections with larger pipelines or trading hubs and other markets. RIGS 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. RIGS 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 provides customers with turn-key natural gas compression services to maximize their natural gas and crude oil production, throughput, and cash flow. The Partnership's integrated solutions include a comprehensive assessment of a customer's natural gas contract compression needs and the design and installation of a compression system that addresses those particular needs. The Partnership is responsible for the installation and ongoing operation, service, and repair of its compression units, which are modified as necessary to adapt to customers' changing operating conditions. The contract compression segment also provides services to certain operations in the gathering and processing segment, creating a portion of the intersegment revenues shown in the table below.

The Partnership's fourth reportable segment, corporate and others, comprises a small regulated interstate pipeline and the Partnership's corporate offices. Revenues in this segment derive from the operations of the regulated interstate pipeline which, prior to the realignment of the segments, was reported within the transportation segment.

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

	Gathering and Processing	Transportation	Contract Compression	Corporate and Others	Eliminations	Total
			(in thousands)			
External Revenue						
For the three months ended March 31, 2009	$ 247,822	$ 3,538	$ 38,488	$ 277	$ -	$ 290,125
For the three months ended March 31, 2008	370,425	9,343	25,267	200	-	405,235
Intersegment Revenue						
For the three months ended March 31, 2009	70,764	8,791	810	-	(80,365)	-
For the three months ended March 31, 2008	31,810	4,150	118	-	(36,078)	-
Cost of Sales						
For the three months ended March 31, 2009	259,438	775	2,317	(153)	(79,476)	182,901
For the three months ended March 31, 2008	346,989	239	2,364	-	(36,003)	313,589
Segment Margin						
For the three months ended March 31, 2009	59,148	11,554	36,981	430	(889)	107,224
For the three months ended March 31, 2008	55,246	13,254	23,021	200	(75)	91,646
Operation and Maintenance						
For the three months ended March 31, 2009	22,636	2,286	12,540	28	(1,448)	36,042
For the three months ended March 31, 2008	18,627	1,391	8,844	6	(23)	28,845
Depreciation and Amortization						
For the three months ended March 31, 2009	17,058	2,448	8,027	356	-	27,889
For the three months ended March 31, 2008	12,670	3,464	5,354	253	-	21,741

Assets						
March 31, 2009	1,059,720	405,315	913,649	136,251	494	2,515,429
December 31, 2008	1,103,770	325,310	881,552	148,007	-	2,458,639
Investment in Unconsolidated Subsidiary						
March 31, 2009	-	400,336	-	-	-	400,336
December 31, 2008	-	-	-	-	-	-
Goodwill						
March 31, 2009	63,232	-	164,882	-	-	228,114
December 31, 2008	63,232	34,244	164,882	-	-	262,358
Expenditures for Long-Lived Assets						
For the three months ended March 31, 2009	23,804	22,367	34,032	52	-	80,255
For the three months ended March 31, 2008	35,219	1,015	61,299	363	-	97,896

The table below provides a reconciliation of total segment margin to net income.

	Three Months Ended	
	March 31, 2009	March 31, 2008
	(in thousands)	
Net income attributable to Regency Energy Partners LP	$ 148,389	$ 10,348
Add (deduct):		
Operation and maintenance	36,042	28,845
General and administrative	14,852	11,271
Gain on asset sales, net	(133,932)	-
Management services termination fee	-	3,888
Depreciation and amortization	27,889	21,741
Income from unconsolidated subsidiary	(336)	-
Interest expense, net	14,227	15,406
Other income and deductions, net	(42)	(176)
Income tax expense	100	251
Net income attributable to the noncontrolling interest	35	72
Total segment margin	$ 107,224	$ 91,646

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10. Equity-Based Compensation

In December 2005, the General Partner approved a 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. The Partnership expects to recognize $13,646,000 of compensation expense related to the non-vested grants over a weighted average period of approximately two-and-a-half years. 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.

The restricted (non-vested) units and common unit options activity for the three months ended March 31, 2009 are as follows.

Restricted (Non-Vested) Units	Units	Weighted Average Grant Date Fair Value
Outstanding at beginning of period	704,050	$ 29.26
Granted	20,000	10.81
Vested	(45,500)	30.99
Forfeited or expired	(9,375)	31.58
Outstanding at end of period	669,175	$ 28.56

Common Unit Options	Units	Weighted Average Exercise Price	Weighted Average Contractual Term (Years)	Aggregate Intrinsic Value* (in thousands)
Outstanding at beginning of period	431,918	$ 21.31		
Granted	-	-		
Exercised	-	-		
Forfeited or expired	(103,300)	21.05		
Outstanding at end of period	328,618	21.40	7.04	$ -
Exercisable at end of period	328,618			

* 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.

11. Fair Value Measures

On January 1, 2008, the Partnership adopted the provisions of SFAS 157 for financial assets and liabilities. On January 1, 2009, the Partnership applied the provisions of SFAS 157 for non-recurring fair value measurements of non-financial assets and liabilities, such as goodwill, indefinite-lived intangible assets, property, plant and equipment and asset retirement obligations. SFAS 157 establishes a three-tiered fair value hierarchy that prioritizes inputs to valuation techniques used in fair value calculations. The three levels of inputs are defined as follows:

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

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

The Partnership's financial assets and liabilities measured at fair value on a recurring basis are risk management assets and liabilities related to interest rate and commodity swaps. Risk management assets and liabilities are valued using discounted cash flow techniques. These techniques incorporate Level 1 and Level 2 inputs such as future interest rates and commodity prices. These market inputs are utilized in the discounted cash flow calculation considering the instrument's term, notional amount, discount rate and credit risk and are classified as Level 2 in the hierarchy. The Partnership has no financial assets and liabilities as of March 31, 2009 valued based on inputs classified as Level 3 in the hierarchy.

The estimated fair value of financial instruments was determined using available market information and valuation methodologies. The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. Restricted cash and related escrow payable approximates fair value due to the relatively short-term settlement period of the escrow payable. Risk management assets and liabilities are carried at fair value. Long-term debt other than the senior notes is comprised of borrowings under which, accrues interest under a floating interest rate structure. Accordingly, the carrying value approximates fair value for the long term debt amounts outstanding. The estimated fair value of the senior notes based on third party market value quotations was $307,450,000 as of March 31, 2009.

12. Subsequent Event

On April 27, 2009, the Partnership declared a distribution of $0.445 per outstanding common unit including units equivalent to the General Partner's two percent interest in the Partnership, and an aggregate distribution of approximately $634,000, with respect to incentive distribution rights, payable on May 14, 2009 to unitholders of record at the close of business on May 7, 2009.

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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.
Joint Venture Formation. On March 17, 2009, the Partnership announced the completion of the transactions included in the Contribution Agreement relating to a new joint venture arrangement among Regency HIG, GECC and the Alinda Investors. The Partnership contributed to HPC RIGS, which owns the Regency Intrastate Gas System, valued at $400,000,000, in exchange for a 38 percent general partnership interest in HPC. GECC and the Alinda Investors contributed $126,500,000 and $526,500,000 in cash, respectively, to HPC in return for a 12 percent and a 50 percent general partnership interest, respectively.

HPC was formed to finance the construction and development of the Partnership's previously announced expansion of its existing natural gas pipeline in north Louisiana and to operate the Regency Intrastate Gas System.

Drilling and Pricing Pressure Trends.

General. Other than in north Louisiana, south Texas and Arkansas where prolific natural gas shale reservoirs are believed to exist, we continue to see a decline in drilling activity in our operating regions. As long as oil and gas prices remain at current levels, we believe that drilling activity will continue to remain low. Currently, we believe that drilling levels are not sufficient to meet ongoing demand and that higher prices will be needed for drilling levels to rise to recent historical levels. Management cannot predict the timing of higher natural gas prices, but if prices remain at current levels for an extended period of time, our business operations could be adversely impacted.

Contract Compression Segment. As a result of depressed natural gas prices, decreased drilling activity, and overall deteriorating economic conditions, our natural gas contract compression segment is experiencing a challenging environment in re-applying horsepower that comes up for contract renewal. Though overall applied horsepower increased slightly for the three month period ending March 31, 2009, compared to levels experienced during 2008, we anticipate continued challenges in redeploying horsepower that comes up for renewal as well as new horsepower sets during the near term.

OUR OPERATIONS. We manage our business and analyze and report our results of operations through three principal 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 own a 38 percent interest in HPC that delivers natural gas from northwest Louisiana to more favorable markets in northeast Louisiana through a 320-mile 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.

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

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 gathering systems and 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 also 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.

Prior to our contribution of our Regency Intrastate Gas System to HPC, we calculated 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.

After our contribution of RIGS to HPC, we will not record segment margin for the transportation segment because the income attributable to HPC will be recorded as income from unconsolidated subsidiary. Because of the materiality of HPC to the Partnership, we are providing a discussion of HPC’s results of operations and cash distributions.

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, 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 income and net cash flows provided by operating activities.

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
	(in thousands)	
Net cash flows provided by operating activities	$ 36,331	$ 57,538
Add (deduct):		
Depreciation and amortization, including debt issuance cost amortization	(28,932)	(22,398)
Income from unconsolidated subsidiary	336	-
Risk management portfolio valuation changes	3,565	(3,098)
Gain on asset sales	133,932	-
Unit based compensation expenses	(1,189)	(794)
Changes in current assets and liabilities:		
Trade accounts receivables and accrued revenues	(22,741)	19,264
Other current assets	(10,458)	(2,800)
Trade accounts payable, accrued cost of gas and liquids, and related party payables	36,948	(25,950)
Other current liabilities	1,022	(18,249)
Other assets and liabilities	(390)	6,907
Net income attributable to the noncontrolling interest	(35)	(72)
Net income attributable to Regency Energy Partners LP	$ 148,389	$ 10,348
Add:		
Interest expense, net	14,227	15,406
Depreciation and amortization	27,889	21,741
Income tax expense	100	251
EBITDA	$ 190,605	$ 47,746

CASH DISTRIBUTIONS. On April 27, 2009, the Partnership declared a distribution of $0.445 per outstanding common unit including units equivalent to the General Partner’s two percent interest in the Partnership, and an aggregate distribution of approximately $634,000, with respect to incentive distribution rights, payable on May 14, 2009 to unitholders of record at the close of business on May 7, 2009.

RESULTS OF OPERATIONS

Partnership

Three Months Ended March 31, 2009 vs. Three Months Ended March 31, 2008

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$ 290,125	$ 405,235	$ (115,110)	28%
Cost of sales	182,901	313,589	(130,688)	42
Total segment margin (1)	107,224	91,646	15,578	17
Operation and maintenance	36,042	28,845	7,197	25
General and administrative	14,852	11,271	3,581	32
Gain on asset sales, net	(133,932)	-	(133,932)	N/M

Management services termination fee	-	3,888	(3,888)	N/M
Depreciation and amortization	27,889	21,741	6,148	28
Operating income	162,373	25,901	136,472	527
Income from unconsolidated subsidiary	336	-	336	N/M
Interest expense, net	(14,227)	(15,406)	1,179	8
Other income and deductions, net	42	176	(134)	76
Income tax expense	(100)	(251)	151	60
Net income attributable to noncontrolling interest	(35)	(72)	37	51
Net income attributable to Regency Energy Partners LP	$ 148,389	$ 10,348	$ 138,041	1,334%
System inlet volumes (MMbtu/d) (2)	1,618,342	1,378,932	239,410	17
Revenue generating horsepower (3)	789,494	615,852	173,642	28

(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

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

	Three Months Ended March 31, 2009	March 31, 2008	Change	Percent
	(in thousands except percentage and volume data)			
Segment Financial and Operating Data:				
Gathering and Processing Segment				
Financial data:				
Segment margin (1) (2)	$ 59,148	$ 55,246	$ 3,902	7%
Operation and maintenance (3)	22,636	18,627	4,009	22
Operating data:				
Throughput (MMbtu/d) (4)	1,038,707	918,950	119,757	13
NGL gross production (Bbls/d)	22,721	23,068	(347)	2
Transportation Segment				
Financial data:				
Segment margin (1) (2)	$ 11,554	$ 13,254	$ (1,700)	13%
Operation and maintenance (3)	2,286	1,391	895	64
Operating data:				
Throughput (MMbtu/d) (4)	812,332	732,006	80,326	11
Contract Compression Segment				
Financial data:				
Segment margin (1)	$ 36,981	$ 23,021	$ 13,960	61%
Operation and maintenance (3)	12,540	8,844	3,696	42
Operating data:				
Revenue generating horsepower (5)	789,494	615,852	173,642	28
Average horsepower per revenue generating compression unit	858	849	9	1
Corporate and Others				
Financial data:				
Segment margin (1) (2)	$ 430	$ 200	$ 230	115%
Operation and maintenance (3)	28	6	22	367

(1) For a reconciliation of 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." Combined segment margin varies from consolidated total segment margin due to inter-segment eliminations between the contract compression, transportation, and gathering and

processing segments.
(2) Segment margins differ from previously disclosed amounts due to functional reorganization of our operating segments.
(3) Combined operation and maintenance expense varies from consolidated operation and maintenance expense due to inter-segment eliminations between the contract compression, transportation, and gathering and processing segments.
(4) Combined throughput volumes for the gathering and processing and transportation segments vary from consolidated system inlet volumes due to inter-segment eliminations.
(5) Revenue generating horsepower is our total available horsepower less horsepower under contract that is not generating revenue and idle horsepower

In addition to the revenue generating horsepower and units owned and operated by the contract compression segment disclosed below, the contract compression segment operates 170,000 horsepower owned by the gathering and processing and transportation segments as of March 31, 2009.

		March 31, 2009	
Horsepower Range	Revenue Generating Horsepower	Percentage of Revenue Generating Horsepower	Number of Units
0-499	62,147	8%	360
500-999	80,587	10%	129
1,000	646,760	82%	431
	789,494	100%	920

Net Income Attributable to the Partnership. Net income attributable to the Partnership for the three months ended March 31, 2009 was $148,389,000 compared to $10,348,000 in the three months ended March 31, 2008, a 1,334 percent increase. The increase in net income attributable to the Partnership was primarily due to the recording of a $133,932,000 gain primarily associated with the assets of RIGS which we contributed to HPC, and an increase in total segment margin of $15,578,000 discussed below. Also contributing to the increase was the absence in 2009 of $3,888,000 in the management services termination fee related to the acquisition of our FrontStreet assets in 2008 and a $1,179,000 decrease in interest expense, net due to lower interest rates. This increase was partially offset by:

· an increase in operation and maintenance expense of $7,197,000 primarily due to an increase in consumable and employee related expense in the contract compression and gathering and processing segments; and
· an increase in depreciation and amortization expense of $6,148,000 related primarily to organic growth projects in the contract compression and gathering and processing segments and the acquisition of Nexus on March 25, 2008.

Segment Margin. Total segment margin for the three months ended March 31, 2009 increased $15,578,000 compared with the three months ended March 31, 2008. This increase was attributable to an increase of $3,902,000 in the gathering and processing segment, an increase of $13,960,000 in the contract compression segment margin, partially offset by a $1,700,000 decrease in transportation segment margin. Combined segment margin varies from consolidated total segment margin due to inter-segments eliminations of $889,000 and $75,000 in the three months ended March 31, 2009 and 2008, respectively. Segment margins differ from previously disclosed amounts due to functional reorganization of our operating segments.

Gathering and processing segment margin increased to $59,148,000 in the three months ended March 31, 2009 from $55,246,000 for the three months ended March 31, 2008. The major components of this increase were as follows:

· $6,654,000 from non-cash changes in the value of certain risk management contracts related to our hedging programs;
· $3,544,000 related to our producer services function, previously reported under the transportation segment.;
· $1,957,000 from the operations of our Nexus assets; and were partially offset by
· $5,521,000 related to lower commodity prices compared to 2008 price levels; and
· $2,732,000 decrease from various other sources.

Transportation segment margin decreased to $11,554,000 for the three months ended March 31, 2009 from $13,254,000 for the three months ended March 31, 2008. The major component of this decrease relates to the contribution of RIGS to HPC on March 17, 2009.

Contract compression segment margin increased to $36,981,000 in the three months ended March 31, 2009 from $23,021,000 for the three months ended months ended March 31, 2008. The increase is primarily attributable to a 173,642 increase in revenue generating horsepower, a 28 percent increase, enhanced by the exclusion of 15 days in 2008 of activity due to the timing of the CDM acquisition. This 15 days also impacts other contract compression segment explanations below.

Operation and Maintenance. Operation and maintenance expense increased to $36,042,000 in the three months ended March 31, 2009 from $28,845,000 for the corresponding period in 2008, a 25 percent increase. This increase is primarily the result of the following factors:

- $4,187,000 increase in consumable expense primarily in the gathering and processing segment and contract compression segment due to increased focus on maintenance of our compression fleet and increase in revenue generating horsepower in the contract compression segment; and
- $3,358,000 increase in employee related expenses primarily in the contract compression and gathering and processing segments due to increase in operating personnel since March 31, 2008 in the contract compression segment associated with the increase in revenue generating horsepower and a change in employee vehicle policy in the gathering and processing segment; and were partially offset by
- $348,000 decrease in various operation and maintenance expense.

General and Administrative. General and administrative expense increased to $14,852,000 in the three months ended March 31, 2009 from $11,271,000 for the same period in 2008, a 32 percent increase. This increase is primarily due to:

- $2,557,000 increase in employee related expenses due to increased employer benefit payments and bonus accrual;
- $972,000 increase in professional and consulting service primarily due to legal fees and fees paid for Sarbanes Oxley compliance in the contract compression segment;
- $383,000 increase in rent expense primarily due to the new office lease for corporate headquarters; and offset by
- $331,000 decrease in general and administrative expense primarily related to reimbursement for the operation and management of HPC.

Gain on Asset Sales, Net. Gain on asset sales net of $133,932,000 (of which $52,857,000 represents the remeasurement of the Partnership retained 38 percent interest to its fair value) in the three months ended March 31, 2009 was primarily associated with assets contributed to HPC, net of transaction costs of $5,158,000.

Depreciation and Amortization. Depreciation and amortization expense increased to $27,889,000 in the three months ended March 31, 2009 from $21,741,000 for the three months ended March 31, 2008, a 28 percent increase. The following factors contributed to this increase:

- $5,993,000 related to various organic growth projects completed since March 31, 2008 in the gathering and processing and contract compression segments;
- $1,067,000 related to our Nexus assets acquired on March 25, 2008; and were partially offset by a
- $1,016,000 decrease in depreciation expense related to the contribution of RIGS to HPC.

Interest Expense, Net. Interest expense, net decreased by $1,179,000, or 8 percent, in the three months ended March 31, 2009 compared to the same period in 2008. Interest expense, net decreased by $4,029,000 due to lower interest rates and was partially offset by an increase of $2,850,000 primarily due to increased levels of borrowing.

HPC

We own a 38 percent interest in HPC and the following management discussion and analysis is for 100 percent of HPC's results of operations. For comparative purposes only, we have combined the results of operations of RIGS from January 1, 2009 to March 17, 2009, with the results of operations of HPC for inception (March 18, 2009) to March 31, 2009 to compare to RIGS for the three months ended March 31, 2008.

	Three Months Ended			
	March 31, 2009	March 31, 2008	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$ 14,155	$ 13,493	$ 662	5%
Cost of sales	599	240	359	150
Segment margin (1)	13,556	13,253	303	2
Operation and maintenance	2,611	1,390	1,221	88
General and administrative	248	-	248	N/M
Depreciation and amortization	3,117	3,464	(347)	10
Operating income	7,580	8,399	(819)	10
Other income and deductions, net	104	(43)	147	342
Net income	$ 7,684	$ 8,356	$ (672)	8%

System inlet volumes (MMbtu/d)	810,848	732,006	78,842	11

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

	Three Months Ended			
	March 31, 2009		March 31, 2008	
	(in thousands)			
Net income	$	7,684	$	8,356
Add (deduct):				
Operation and maintenance		2,611		1,390
General and administrative		248		-
Depreciation and amortization		3,117		3,464
Other income and deductions, net		(104)		43
Total segment margin	$	13,556	$	13,253

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Results of Operations Discussion. Net income for the three months ended March 31, 2009 was $7,684,000 compared to $8,356,000 in the three months ended March 31, 2008, an 8 percent decrease. The decrease in net income was primarily attributable to an increase in operation and maintenance expense of $1,221,000 mainly resulting from increased contractor expense related to compression operations. Also contributing to the decrease in net income was an increase in general and administrative expense of $248,000 primarily due to the recording of a management fee paid to the Partnership for the 14 days HPC owned RIGS in the three months ended March 31, 2009. Partially offsetting these decreases in net income were the following factors:

- a decrease in depreciation and amortization expense of $347,000 primarily due to the fact that RIGS' assets prior to contribution to HPC were classified as held for sale and therefore no depreciation or amortization expense was recorded from March 1, 2009 to March 17, 2009;
- an increase in segment margin of $303,000 primarily due to an increase in system inlet volumes; and
- an increase in other income and deductions, net of $147,000 due to interest income earned the last 14 days of March 2009 by HPC from the unused portion of capital contributed by GECC and the Alinda Investors.

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 income and net cash flows provided by operating activities.

HPC's EBITDA for the three months ended March 31, 2009 and 2008 is presented below.

	Three Months Ended			
	March 31, 2009		March 31, 2008	
	(in thousands)			
Net income	$	7,684	$	8,356
Add:				
Depreciation and amortization		3,117		3,464
EBITDA	$	10,801	$	11,820

Cash Distributions. On April 14, 2009, the HPC management committee declared as a distribution of $5,000,000 payable on April 30, 2009, of which the Partnership received its pro-rata share of $1,900,000.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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, 2008.

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

Liquidity

We expect our sources of liquidity to include:

- cash generated from operations;
- borrowings under our credit facility;
- distributions received from unconsolidated subsidiaries;
- operating lease facilities;
- debt offerings; and
- issuance of additional partnership units.

We have experienced, and expect to continue to experience, substantial capital expenditure and working capital needs. At March 31, 2009, the Partnership has purchase obligations totaling approximately $39,787,000 for the purchase of major compression components that extend until the year ending December 31, 2009.

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

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile. The debt and equity capital markets have been exceedingly distressed. These issues, along with significant write-offs in the financial services sector, the re-pricing of credit risk and the current weak economic conditions have made, and will likely continue to make it difficult to obtain funding. The cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. We expect that our ability to issue debt and equity at prices that are similar to offerings in recent years will be limited as long as capital markets remain constrained.

Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to our current debt and reduced and, in some cases, ceased to provide funding to borrowers. For example, as a result of Lehman filing a petition under Chapter 11 of the U.S. Bankruptcy Code, a subsidiary of Lehman that is a committed lender under our credit facility has declined requests to honor its commitment to lend under our credit facility. The total amount available to us under our credit facility as of April 30, 2009 was $93,632,000, which has been reduced by the amount of Lehman's commitment of $5,578,000 that is no longer available to us. If we repay any of the amounts we have already borrowed from Lehman, we may not be able to reborrow such amounts. We may be unable to utilize the full borrowing capacity under our credit facility if other lenders are not willing to provide additional funding to make up the portion of the credit facility commitments that Lehman's subsidiary has refused to fund or if any of the remaining committed lenders are unable or unwilling to fund their respective portion of any funding request we make under our credit facility.

We expect our growth capital expenditures to be approximately $107,000,000 in 2009 and $100,000,000 in 2010, exclusive of growth capital expenditures related to the Haynesville Expansion Project. Our anticipated 2009 organic growth capital expenditures of $107,000,000 include $82,000,000 for additional compression for our contract compression segment and $25,000,000 for the expansion of our gathering and processing facilities. We expect a significant portion of our anticipated 2009 contract compression capital expenditures to be made via our $75,000,000 CDM operating lease facility with Caterpillar Financial Services.

Although we intend to move forward with certain planned internal growth projects, we may further revise the timing and scope of these projects as necessary to adapt to existing economic conditions, and the benefits expected to accrue to our unitholders from our expansion activities may be diminished by substantial cost of capital increases during this period. As a result of these costs, our cash flows may decrease, which could impair our liquidity position and require us to reduce our distributions to unitholders.

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 and gas related drilling activity, 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.

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 may experience working capital deficits as we fund construction expenditures out of working capital until they are permanently financed. Our working capital is also influenced by current risk management assets and liabilities due to fair market value changes in our derivative positions being reflected on our balance sheet. These represent our expectations for the settlement of risk management rights and obligations over the next 12 months, and so must be viewed differently from trade accounts receivable and accounts payable which settle over a much shorter span of time. When our derivative positions are settled, we expect an offsetting physical transaction, and, as a result, we do not expect risk management assets and liabilities to affect our ability to pay bills as they come due. Our contract compression segment records deferred revenues as 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 increased by $12,262,000 from December 31, 2008 to March 31, 2009, primarily due to:

- an increase in net accounts receivable and payable of $16,656,000 due primarily to increased total segment margin and the timing of cash receipts and disbursements;
- an increase in cash and cash equivalents of $5,979,000;
- an increase in net risk management asset and liabilities of $3,989,000 due primarily to lower commodity prices associated with our derivatives portfolio; and
- a decrease in other current liabilities of $1,022,000 primarily due to a decrease in escrow payable of $8,521,000 associated with environmental remediation and past acquisitions, mostly offset by an increase in interest payable of $7,485,000 due to interest accrued on our senior notes paid semi-annually in June and December.

Partially offsetting these increases in working capital was a decrease in other current assets due primarily to a decrease in restricted cash of $8,521,000 related to the reduced escrow payable as previously discussed.

Cash Flows from Operations. Net cash flows provided by operating activities decreased $21,207,000, or 37 percent, for the three months ended March 31, 2009 as compared to the three months ended March 31, 2008. Although total segment margin increased and was partially offset by increased operation and maintenance and general and administrative expenses, our cash flows from operations decreased, primarily due to the timing of cash receipts and disbursements associated with receivables and payables.

Cash Flows from Investing Activities. Net cash flows provided by investing activities was $2,842,000 in the three months ended March 31, 2009 compared to net cash flows used in investing activities of $671,955,000 in the three months ended March 31, 2008. In the three months ended March 31, 2009, proceeds from an asset sale more than offset our capital expenditures. In the three months ended March 31, 2008, we acquired FrontStreet, CDM and Nexus.

Cash Flows from Financing Activities. Net cash flows used in financing activities was $33,194,000 in the three months ended March 31, 2009 compared to net cash flows provided by financing activities of $592,322,000 in the three months ended March 31, 2008. In the three months ended March 31, 2009, cash flows used in financing activities primarily related to partner distributions associated with fourth quarter 2008 activity. In the three months ended March 31, 2008, cash flows provided by financing activities were primarily associated with borrowings for our FrontStreet, CDM and Nexus acquisitions.

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 three months ended March 31, 2009, we incurred $45,208,000 of growth capital expenditures, which excludes growth capital expenditures related to the Haynesville Expansion Project. The expenditures primarily related to:

- $38,660,000 for the fabrication of new compression packages and ancillary assets for our contract compression segment; and
- $6,548,000 for various projects in the gathering and processing segment.

Expenditures incurred by us for the Haynesville Expansion project prior to contribution of RIGS to HPC in the amount of $80,607,000 were reimbursed by HPC upon contribution.

Maintenance Capital Expenditures. In the three months ended March 31, 2009, we incurred $4,864,000 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.

Capital Resources

Credit Ratings. Our credit ratings as of March 31, 2009 are provided below.

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

Fourth Amended and Restated Credit Agreement. RGS is a party to the Fourth Amended and Restated Credit Agreement dated as of August 15, 2006 among RGS, the Partnership, the guarantors party thereto, (as amended, the “Credit Agreement”), and on March 17, 2009, RGS closed Amendment Agreement No. 7 (the “Amendment”) to amend the Credit Agreement.

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

The Amendment provides, (a) the alternate base rate used to calculate interest on base rate loans will be calculated based on the greatest to occur of a base rate, a federal funds effective rate plus 0.50 percent and an adjusted LIBOR rate for a borrowing with a one-month interest period plus 1.50 percent, (b) the applicable margin that is used in calculating interest shall range from 1.50 percent to 2.25 percent for base rate loans and from 2.50 percent to 3.25 percent for Eurodollar loans and (c) commitment fees will range from 0.375 percent to 0.500 percent.

The Amendment prohibits RGS or its subsidiaries from allowing HPC to incur or permit to exist any preferred interests or indebtedness for borrowed money of HPC prior to the completion date of the Haynesville Expansion Project. RGS and GECC have agreed with the lenders that, after the closing of the Contribution Agreement, they will not permit their representatives on the management committee of HPC to violate such restriction.

GECC Credit Facility. Upon the closing of our contribution of RIGS to HPC, the $45,000,000 GECC credit facility terminated.

Contractual Obligations. The following table summarizes our contractual cash obligations for long-term debt and purchase obligations as of March 31, 2009.

	Payment Period				
	Total	2009	2010-2011	2012-2013	Thereafter
	(in thousands)				
Long-term debt (including interest) (1)	$ 1,376,012	$ 59,333	$ 899,298	$ 417,381	$ -
Purchase obligations	39,787	39,787	-	-	-
Total (2) (3)	$ 1,415,799	$ 99,120	$ 899,298	$ 417,381	$ -

(1) Assumes a constant LIBOR interest rate of 2.0 percent plus the applicable margin (3 percent as of March 31, 2009) 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 $8,080,000 as the amount payable by period can not be reasonably estimated.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

	2009	2010
NGL	97%	36%
Condensate	75	76
Natural gas	83	-

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

The following table sets forth certain information regarding our NGL and interest rate swaps outstanding at March 31, 2009. The relevant index price for commodities that we pay is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas as reported by the Oil Price Information Service (OPIS).

Period	Underlying	Notional Volume/Amount		We Pay	We Receive		Fair Value Asset/(Liablity) (in thousands)
April 2009-December 2009	Ethane	528	(MBbls)	Index	$ 0.80	($/gallon)	$ 10,100
April 2009-December 2010	Propane	589	(MBbls)	Index	$ 0.9815-$1.5325	($/gallon)	14,786
April 2009-December 2010	Iso Butane	134	(MBbls)	Index	$ 1.685-$1.915	($/gallon)	4,893
April 2009-December 2010	Normal Butane	254	(MBbls)	Index	$ 1.166-$1.895	($/gallon)	6,273
April 2009-December 2010	Natural Gasoline	260	(MBbls)	Index	$ 1.4975-$2.53	($/gallon)	10,122
April 2009-December 2010	West Texas Intermediate Crude	416	(MBbls)	Index	$ 68.17-$121.3	($/Bbls)	16,047
April 2009-December 2010	Natural gas	2,750,000	(MMBtu)	Index	$ 6.67-$6.705	($/MMBtu)	6,599
April 2009-December 2010	Interest Rate	$ 300,000,000		2.40%	One-month	LIBOR	(4,605)
Credit risk adjustment							(1,980)
						Total Fair Value	$ 62,235

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 March 31, 2009 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 the 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, 2008, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing our partnership.

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

None.

Item 6. Exhibits

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

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

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

May 14, 2009