Regency Energy Partners LP
Form 10-Q
August 14, 2006

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

(Mark One)

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2006

OR

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

For the transition period from __________ to __________

Commission File Number: 0001-338613

REGENCY ENERGY PARTNERS LP

(Exact name of registrant as specified in its charter)

DELAWARE (State or other jurisdiction of incorporation or organization)	16-1731691 (I.R.S. Employer Identification No.)
1700 PACIFIC AVENUE, SUITE 2900 DALLAS, TX (Address of principal executive offices)	75201 (Zip Code)

(214) 750-1771
(Registrant s telephone number, including area code)

NONE
(Former name, former address and former fiscal year, if changed since last report.)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

þ Yes o No

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

o Yes þ No

The issuer had 19,536,396 common units and 19,103,896 subordinated units outstanding as of August 11, 2006.

FORWARD-LOOKING STATEMENTS

Certain matters discussed in this report, excluding historical information, as well as some statements by Regency Energy Partners LP (the Partnership) in periodic press releases and some oral statements of Partnership officials during presentations about the Partnership, include certain forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Statements using words such as anticipate, believe, intend, project, plan, continue, estimate, forecast, may, or similar identify forward-looking statements. Although the Partnership believes such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that these objectives will be reached.

Actual results may differ materially from any results projected, forecasted, estimated or expressed in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks, difficult to predict, and beyond management s control. For additional discussion of risks, uncertainties and assumptions, see the Partnership s Annual Report on Form 10-K for the fiscal year ended December 31, 2005 filed with the Securities and Exchange Commission on March 31, 2006.

PART I FINANCIAL INFORMATION

Item 1. Financial Statements

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

	June 30, 2006	December 31, 2005
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 6,390	$ 3,669
Restricted cash	5,654	5,533
Accounts receivable, net of allowance of $169 in 2006 and 2005	70,151	78,782
Assets from risk management activities	2,373	1,717
Other current assets	3,970	3,950
Total current assets	88,538	93,651
Property, plant and equipment:		
Gas plants and buildings	46,944	46,399
Gathering and transmission systems	406,609	397,481
Other property, plant and equipment	44,467	41,470
Construction - in - progress	38,731	16,738
Total property, plant and equipment	536,751	502,088
Less accumulated depreciation	(35,722)	(21,505)
Property, plant and equipment, net	501,029	480,583
Intangible and other assets:		
Intangible assets, net of amortization of $2,962 in 2006 and $2,027 in 2005	15,435	16,370
Goodwill	57,552	57,552
Long-term assets from risk management activities	15	1,333
Other, net of amortization of debt issuance costs of $498 in 2006 and $271 in 2005	1,992	4,835
Total intangible and other assets	74,994	80,090
TOTAL ASSETS	**$ 664,561**	**$ 654,324**
LIABILITIES & PARTNERS CAPITAL		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 75,919	$ 99,745
Escrow payable	5,654	5,533
Accrued taxes payable	2,737	2,266

Liabilities from risk management activities	14,782	11,312
Other current liabilities	1,710	2,445
Total current liabilities	100,802	121,301
Long term liabilities from risk management activities	6,857	4,895
Long-term debt	389,750	358,350
Commitments and contingencies		
Partners Capital or Member Interest:		
Member interest		180,740
Common units (21,969,480 units authorized and 19,536,396 units issued and outstanding at June 30, 2006)	88,867	
Subordinated units (19,103,896 units authorized, issued and outstanding at June 30, 2006)	88,970	
General partner interest	3,632	
Accumulated other comprehensive loss	(14,317)	(10,962)
Total partners capital or member interest	167,152	169,778
TOTAL LIABILITIES & PARTNERS CAPITAL OR MEMBER INTEREST	**$ 664,561**	**$ 654,324**

See accompanying notes to unaudited condensed consolidated financial statements.

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

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
REVENUE				
Gas sales	$ 117,978	$ 87,124	$ 256,758	$ 167,313
NGL sales	60,572	38,017	110,966	74,930
Gathering, transportation and other fees	12,397	5,766	22,779	11,230
Net unrealized and realized gain/(loss) from risk management activities	(2,425)	3,111	(4,082)	(16,226)
Other	4,581	3,332	8,157	6,715
Total revenue	193,103	137,350	394,578	243,962
EXPENSE				
Cost of gas and liquids	161,652	112,055	335,752	218,403
Operating expenses	5,613	5,631	11,618	10,431
General and administrative	5,820	3,688	10,628	6,053
Management services termination fee			9,000	
Depreciation and amortization	7,692	5,219	15,171	10,382
Total operating expense	180,777	126,593	382,169	245,269
OPERATING INCOME (LOSS)	**12,326**	**10,757**	**12,409**	**(1,307)**
OTHER INCOME AND DEDUCTIONS				
Interest expense, net	(6,753)	(5,018)	(13,193)	(8,207)
Other income and deductions, net	71	49	158	108
Total other income and deductions	(6,682)	(4,969)	(13,035)	(8,099)
NET INCOME (LOSS) FROM CONTINUING OPERATIONS	**5,644**	**5,788**	**(626)**	**(9,406)**
DISCONTINUED OPERATIONS				
Income from operations of Regency Gas Treating LP (including gain on disposal of $626)		694		747
NET INCOME (LOSS)	**5,644**	**$ 6,482**	**(626)**	**$ (8,659)**
Less:				
Net income through January 31, 2006			1,580	

Net income (loss) for partners	**$**	**5,644**	**$**	**(2,206)**
General partner s interest		113		(44)
Limited partners interest	$	5,531	$	(2,162)
Basic weighted average number of units outstanding		38,207,792		38,207,792
Basic net income (loss) per limited partner unit	$	0.14	$	(0.06)
Diluted weighted average number of units outstanding		38,273,998		38,207,792
Diluted net income (loss) per limited partner unit	$	0.14	$	(0.06)

See accompanying notes to unaudited condensed consolidated financial statements.

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

	Six Months Ended June 30, 2006	2005
OPERATING ACTIVITIES		
Net loss	**$ (626)**	**$ (8,659)**
Adjustments to reconcile net loss to net cash flows provided by operating activities:		
Depreciation and amortization	15,398	11,059
Risk management portfolio valuation changes	(811)	13,337
Unit based compensation expenses	1,089	
Gain on the sale of Regency Gas Treating LP assets		(626)
Cash flow changes in current assets and liabilities:		
Accounts receivable	8,631	4,267
Other current assets	(20)	(399)
Accounts payable and accrued liabilities	(11,751)	(5,972)
Accrued taxes payable	471	287
Other current liabilities	(735)	(574)
Proceeds from early termination of interest rate swap	3,550	
Other assets	2,804	(149)
Net cash flows provided by operating activities	**18,000**	**12,571**
INVESTING ACTIVITIES		
Capital expenditures	(46,756)	(22,295)
Sale of Regency Gas Treating LP assets		6,000
Cash outflows for acquisition by HM Capital Investors		(5,808)
Net cash flows used in investing activities	**(46,756)**	**(22,103)**
FINANCING ACTIVITIES		
Repayments under credit facilities		(1,000)
Net borrowings under revolving credit facilities	31,400	10,000
Debt issuance costs	(189)	(118)
Partner distributions	(8,735)	
IPO proceeds, net of issuance costs	256,953	
Capital reimbursement to HM Capital Partners LLC	(195,757)	
Working capital distribution to HM Capital Partners LLC	(48,000)	
Offering costs	(4,195)	
Net proceeds from exercise of over allotment option	26,163	
Over allotment option net proceeds to HM Capital Investors	(26,163)	

Net cash flows provided by financing activities		**31,477**		**8,882**
Net increase (decrease) in cash and cash equivalents		2,721		(650)
Cash and cash equivalents at beginning of period		**3,669**		**3,272**
Cash and cash equivalents at end of period	**$**	**6,390**	**$**	**2,622**
Supplemental cash flow information				
Interest paid, net of amounts capitalized	**$**	**12,853**	**$**	**7,834**
Non-cash capital expenditures in accounts payable	**$**	**9,225**	**$**	**5,755**

See accompanying notes to unaudited condensed consolidated financial statements.

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Regency Energy Partners LP
Condensed Consolidated Statement of Member Interest and Partners Capital
Unaudited
(in thousands except unit data)

	Common Units	Subordinated Units	Member Interest	Common Unitholders	Subordinated Unitholders	General Partner Interest	Accumulated Other Comprehensive Income	Total
Balance January 1, 2006			$ 180,740	$	$	$	$ (10,962)	$ 169,778
Net income through January 31, 2006			1,580					1,580
Net hedging gain reclassified to earnings							616	616
Net change in fair value of cash flow hedges							2,581	2,581
Balance January 31, 2006			182,320				(7,765)	174,555
Contribution of net investment to unitholders	5,353,896	19,103,896	(182,320)	89,337	89,337	3,646		
Proceeds from IPO, net of issuance costs	13,750,000			125,907	125,907	5,139		256,953
Net proceeds from exercise of over allotment option	1,400,000			26,163				26,163
Over allotment option net proceeds to HM Capital Investors	(1,400,000)			(26,163)				(26,163)
Capital reimbursement to HM Capital Partners LLC				(119,441)	(119,441)	(4,875)		(243,757)
Offering costs				(2,056)	(2,056)	(83)		(4,195)
Issuance of restricted	432,500							

common units								
Partner distributions				(4,327)	(4,235)	(173)		(8,735)
Net loss from February 1, 2006 through June 30, 2006				(1,092)	(1,070)	(44)		(2,206)
Unit based compensation expenses				539	528	22		1,089
Net hedging gain reclassified to earnings							2,106	2,106
Net change in fair value of cash flow hedges							(8,658)	(8,658)
Balance June 30, 2006	19,536,396	19,103,896	$	$ 88,867	$ 88,970	$ 3,632	$ (14,317)	$ 167,152

See accompanying notes to unaudited 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 and Basis of Presentation The unaudited condensed consolidated financial statements presented herein contain the results of Regency Energy Partners LP, a Delaware limited partnership (Partnership), and its predecessor, Regency Gas Services LLC (Predecessor). The Partnership was formed on September 8, 2005 for the purpose of converting the Predecessor to a master limited partnership engaged in the business of gathering, treating, processing, transporting, and marketing natural gas and natural gas liquids (NGLs). The historical financial statements prior to the closing of the Partnership s IPO (See Note 2) are the same as those of the Predecessor. The accompanying unaudited condensed consolidated financial statements include the assets, liabilities, results of operations and cash flows of the Partnership and its wholly owned subsidiaries, Regency Gas Services LP (formerly Regency Gas Services LLC), Regency Intrastate Gas LLC, Regency Midcon Gas LLC, Regency Liquids Pipeline LLC, Regency Gas Gathering and Processing LLC, Gulf States Transmission Corporation, Regency Gas Services Waha LP, Regency NGL Marketing LP and Regency Gas Marketing LP (formerly Regency Gas Treating LP). These subsidiaries are Delaware limited liability companies or limited partnerships except for Gulf States Transmission Corporation, which is a Louisiana corporation. The Partnership operates and manages its business as two reportable segments: a) gathering and processing, and b) transportation. (See Note 9)

The unaudited financial information as of June 30, 2006 and for the three and six months ended June 30, 2006 and 2005 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, 2005 and, in the opinion of the Partnership s management, reflects all adjustments necessary for a fair presentation of the financial position and the results of operations for such interim periods in accordance with accounting principles generally accepted in the United States of America (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. Certain prior year amounts have been reclassified to conform to current year presentation.

Use of Estimates The unaudited condensed consolidated financial statements have been prepared in conformity with GAAP, which necessarily include the use of estimates and assumptions by management. Actual results could differ from these estimates. In March 2006, the Partnership implemented a process for estimating certain revenue and expenses as actual amounts are not confirmed until after the financial closing process due to the standard settlement dates in the gas industry. The Partnership does not expect actual results to differ materially from its estimates.

Intangible Assets All separately identified intangible assets are amortized using the straight-line method with no residual value. Amortization expense for the three month and six month periods ended June 30, 2006 was $468,000 and $935,000. The estimated annual amortization for each of the next five years is $1,870,000.

Equity-Based Compensation The Partnership adopted Statement of Financial Accounting Standards (SFAS) No. 123(R), Share-Based Payment , as amended, during the first quarter of 2006 which did not result in a change in accounting principles. Subsequent to the IPO, the Partnership began recording equity based compensation in February 2006. (See Note 10)

Earnings Per Unit Basic net income per limited partner unit is computed in accordance with SFAS No. 128, Earnings Per Share , as interpreted by EITF Issue No. 03 6 (EITF 03 6), Participating Securities and the Two Class method under FASB Statement No. 128 , by dividing limited partners interest, after deducting the general partners interest, in net income by the weighted average number of common and subordinated units outstanding. In periods when the Partnership s aggregate net income exceeds the aggregate distributions, EITF 03 6 requires the Partnership to present earnings per unit as if all of the earnings for the periods were distributed. Diluted net income per limited partner unit is computed by dividing limited partners interest in net income, after deducting the general partner s interest, by the weighted average number of common and subordinated units outstanding and the effect of nonvested restricted units and unit options computed using the treasury stock method.

2. Initial Public Offering

On February 3, 2006, the Partnership offered and sold 13,750,000 common units, representing a 35.3 percent limited partner interest in the Partnership, in its initial public offering, or IPO, at a price of $20.00 per unit. Total proceeds from the sale of the units were $275,000,000, before offering costs and underwriting commissions. The Partnership s common units began trading on the NASDAQ National Market under the symbol RGNC.

Concurrently with the consummation of the IPO, the Predecessor was converted to a limited partnership. All the member interests in the Predecessor were contributed to the Partnership by Regency Acquisition LP (Acquisition), an affiliate of HM Capital Partners LLC (HM Capital Partners), in exchange for 19,103,896 subordinated units representing a 49 percent limited partner interest in the Partnership; 5,353,896 common units representing a 13.7 percent limited partner interest in the Partnership; a 2 percent general partner interest in the Partnership; incentive distribution rights; and the right to reimbursement of $195,757,000 of capital expenditures comprising most of the initial investment by Acquisition in the Predecessor.

The proceeds of the Partnership s initial public offering were used: to distribute $195,757,000 to Acquisition in reimbursement of its capital investment in the Predecessor and to replenish $48,000,000 of working capital assets distributed to Acquisition immediately prior to the IPO; to pay $9,000,000 to an affiliate of Acquisition to terminate two management services contracts; and to pay $22,000,000 of underwriting commissions, structuring fees and other offering costs. In connection with the IPO, the Partnership incurred direct costs totaling $4,195,000 and has charged these costs against the gross proceeds from the Partnership s IPO as a reduction to equity in the first quarter of 2006.

On March 8, 2006, the Partnership sold an additional 1,400,000 common units at a price of $20 per unit as the underwriters exercised a portion of their over allotment option. The net proceeds from the sale were used to redeem an equivalent number of common units held by Acquisition.

3. Comprehensive Income (Loss)

Comprehensive income (loss) consists of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006 (1)	2005
	(in thousands)			
Net income (loss)	$ 5,644	$ 6,482	$ (2,206)	$ (8,659)
Hedging losses reclassified to earnings	1,909		2,106	
Net change in fair value of cash flow hedges	(10,504)		(8,658)	
Comprehensive income (loss)	$ (2,951)	$ 6,482	$ (8,758)	$ (8,659)

(1) Excludes $4,777 of comprehensive income related to Predecessor for the period of January 1, 2006 to January 31, 2006.

4. Income per Limited Partner Unit

The following data show the amounts used in computing limited partner earnings per unit and the effect on income and the weighted average number of units of dilutive potential common units.

	Three Months Ended June 30, 2006	Six Months Ended June 30, 2006
	(in thousands except unit data)	
Net income (loss)	$ 5,644	$ (2,206)

Adjustments:				
General partner s equity ownership		113		(44)
Limited partners interest in net income	$	5,531	$	(2,162)
Weighted average limited partner units basic		38,207,792		38,207,792
Limited partners basic income per unit	$	0.14	$	(0.06)
Weighted average limited partner units basic		38,207,792		38,207,792
Dilutive effect to restricted units and stock options		66,206		
Weighted average limited partner units dilutive		38,273,998		38,207,792
Limited partners diluted income per unit	$	0.14	$	(0.06)

Earnings per unit for the six months ended June 30, 2006 reflect only the earnings for the five months since the closing of the Partnership s initial public offering on February 3, 2006. For convenience, January 31, 2006 has been used as the date of the change in ownership. Accordingly, results for January 2006 have been excluded from the calculation of earnings per unit. Potentially dilutive units related to the Partnership s long-term incentive plan of 432,500 restricted common units and 731,500 common unit options have been excluded from diluted earnings per unit as the effect is antidilutive for the six month period ended June 30, 2006. Furthermore, while the non-vested (or restricted) units are deemed to be outstanding for legal purposes, they have been excluded from the calculation of basic earnings per unit in accordance with SFAS No. 128. For all periods presented, earnings per unit is the same for common units and for subordinated units.

The Partnership Agreement requires that the general partner shall receive a 100 percent allocation of income until its capital account is made whole for all of the net losses allocated to it in prior periods.

On May 15, 2006 the Partnership paid a distribution of $0.2217 per common and subordinated unit. The distribution constitutes the minimum quarterly distribution of $0.35 (or $1.40 per year), prorated for the period in the first quarter of 2006 since the Partnership s February 3, 2006 initial public offering.

5. Risk Management Activities

Effective July 1, 2005, the Partnership elected hedge accounting for its ethane, propane, butane and natural gasoline swaps, as well as for its interest rate swaps. These contracts are accounted for as cash flow hedges under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities , as amended. Prior to the election of hedge accounting, unrealized and realized gains and (losses) of $3,111,000 and ($16,226,000), respectively, were recorded as a charge against revenue during the three month and six month periods ended June 30, 2005.

As of June 30, 2006, the Partnership s hedging positions accounted for as cash flow hedges reduce exposure to variability of future commodity prices through 2008 and interest rates through March 2007. The net fair value of the Partnership s risk management activities was a liability of approximately $19,251,000 as of June 30, 2006. The Partnership expects to reclassify $10,565,000 of losses into earnings from other comprehensive income (loss) in the next twelve months. The Partnership recorded no amounts to the statement of operations for the three or six months ended June 30, 2006 for hedge ineffectiveness.

Upon the early termination of an interest rate swap with a notional debt amount of $200,000,000 that was effective from April 2007 through March 2009, the Partnership received $3,550,000 in cash from the counterparty. This amount will be reclassified from accumulated other comprehensive income (loss) to interest expense, net over the originally projected period (i.e., April 2007 through March 2009) of the hedged forecasted transaction or when it is determined the hedged forecasted transaction is probable of not occurring.

6. Long-Term Debt

Obligations under the Partnership s credit facility are as follows:

	June 30, 2006	December 31, 2005
	(in thousands)	
Term Loans	$ 308,350	$ 308,350
Revolving Loans	81,400	50,000
Long-term Debt	$ 389,750	$ 358,350
Total Facility Limit	$ 468,350	$ 468,350
Long-term Debt	(389,750)	(358,350)
Letters of Credit	(6,582)	(10,700)
Credit Available	$ 72,018	$ 99,300

The outstanding balances of term debt and revolver debt under the Partnership s credit agreement bear interest at either London Inter-Bank Offer Rate (LIBOR) plus margin or at Alternative Base Rate (equivalent to the US prime lending rate) plus margin, or a combination of both. The weighted average interest rates for the revolving and term loan facilities, including interest rate swap settlements, commitment fees, and amortization of debt issuance costs were 6.99 percent and 6.88 percent for the six months ended June 30, 2006 and 2005, respectively, and 7.03 percent and

7.11 percent for the three months ended June 30, 2006 and 2005, respectively.

Upon the completion of the Partnership s IPO, further amendments to the credit agreement became effective that permit distributions to unitholders, eliminated covenants requiring the payment of excess cash flows to reduce principal, and modified covenants related to coverage ratios so as to make them less restrictive. At June 30, 2006, the Partnership was in compliance with these covenants.

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7. Commitments and Contingencies

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

Environmental Waha Phase I. A Phase I environmental study was performed on the Waha assets in connection with the pre-acquisition due diligence process in 2004. Most of the identified environmental contamination has either been remediated or was being remediated by the previous owners or operators of the properties. The estimated potential environmental remediation cost ranges from $1,900,000 to $3,100,000. No governmental agency has required the Partnership to undertake these remediation efforts. The Partnership believes that the likelihood it will be liable for any significant remediation liabilities with respect to these matters 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 in 2014) with a $10,000,000 limit subject to certain deductibles.

El Paso Claims Under the purchase and sale agreement, or PSA, pursuant to which the Partnership purchased north Louisiana and Midcontinent assets from affiliates of El Paso Field Services, LP, or El Paso, in 2003, El Paso indemnified the Partnership (subject to a limit of $84,000,000) for environmental losses as to which El Paso was deemed responsible. Of the cash escrowed for this purpose at the time of sale, $5,654,000 remained in escrow at June 30, 2006. Upon completion of a Phase II investigation of various assets so acquired (the Phase II Assets), El Paso was notified of indemnity claims of approximately $5,400,000 for environmental liabilities. In related discussions, El Paso denied all but $280,000 of these claims (which it evaluated at $75,000 and agreed to cure itself). In these discussions, the Partnership agreed, at El Paso s request, to install permanent monitoring wells at the facilities where ground water impacts were indicated by the Phase II activities. The Partnership also agreed to withdraw its claims with respect to all but seven of the Phase II Assets (which comprise those subject to accepted claims).

A Final Site Investigations Report with respect to those Phase II Assets has since been prepared and issued based on information obtained from the permanent monitoring wells. Environmental issues exist with respect to four facilities, including the two subject to accepted claims and two of the Partnership s processing plants. The estimated remediation costs associated with the processing plants aggregate $2,750,000. The Partnership believes that any of its obligations to remediate the properties is subject to the indemnity under the El Paso PSA, and intends to reinstate the claims for indemnification for these plant sites.

ODEQ Notice of Violation In March 2005, the Oklahoma Department of Environmental Quality, or ODEQ, sent a notice of violation, alleging that the Partnership operates the Mocane processing plant in Beaver County, Oklahoma in violation of the National Emission Standard for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities, or NESHAP, and the requirements to apply for and obtain a federal operating permit (Title V permit). The ODEQ issued an order requiring the Partnership to apply for a Title V permit with respect to emissions from the Mocane processing plant with which the Partnership has complied. No fine or penalty was imposed by the ODEQ and as of June 30, 2006 the matter is fully resolved.

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

Texas Tax Legislation In the three months ended June 30, 2006, the State of Texas passed legislation that imposes a margin tax on partnerships and master limited partnerships. The Partnership currently estimates that the effect of this legislation will not have a material effect on its results of operations, cash flows, or financial condition.

8. Related Party Transactions

Concurrent with the closing of the Partnership s IPO, the Partnership paid $9,000,000 to an affiliate of HM Capital Partners LLC to terminate two management services contracts with a remaining term of 9 years and a minimum annual obligation of $1,000,000.

The employees operating the assets, as well as the general and administrative employees are employees of Regency GP LLC, the Partnership s managing general partner. Pursuant to the partnership agreement, the managing general partner receives a monthly reimbursement for all direct and indirect expenses that it incurs on behalf of the Partnership. Reimbursements of $6,314,000 and $3,438,000 were recorded in the Partnership s financial statements during the six and three months ended June 30, 2006 as operating expenses or general and administrative expenses, as appropriate.

The Partnership made cash distributions of $4,752,000 during the three months ended June 30, 2006 to HM Capital and affiliates.

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9. Segment Information

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

The transportation segment uses pipelines to move pipeline quality gas to interconnections with larger pipelines, to trading hubs, or to other markets. The Partnership performs transportation services for shipping customers under firm or interruptible arrangements. In either case, revenues are primarily fee based and involve minimal direct exposure to commodity price fluctuations. The transportation segment also includes the Partnership s natural gas marketing business in which the Partnership, for its account, 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, thereby creating the intersegment revenues shown in the table below.

Management evaluates the performance of each segment and makes capital allocation decisions through the separate consideration of segment margin and operating expense. Segment margin is defined as total revenues, including service fees, less cost of gas and liquids and other costs of sales. The Partnership believes segment margin is an important measure because it is directly related to volumes and commodity price changes. Operating expenses are a separate measure used by management to evaluate operating performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portions of the Partnership s operating expenses. These expenses are largely independent of the volume throughput but fluctuate depending on the activities performed during a specific period. The Partnership does not deduct operating expenses from total revenues in calculating segment margin because management separately evaluates commodity volume and price changes in segment margin. Results for each income statement period, together with amounts related to balance sheets for each segment, are shown below.

	Gathering and Processing	Transportation	Corporate	Eliminations	Consolidated Total
			(in thousands)		
External Revenue					
Quarter ended June 30, 2006	$126,207	$ 66,896	$	$	$193,103
Quarter ended June 30, 2005	101,521	35,829			137,350
Six months ended June 30, 2006	260,282	134,296			394,578
Six months ended June 30, 2005	177,618	66,344			243,962
Intersegment Revenue					
Quarter ended June 30, 2006		5,175		(5,175)	
Quarter ended June 30, 2005		7,351		(7,351)	
Six months ended June 30, 2006		13,645		(13,645)	
Six months ended June 30, 2005		15,689		(15,689)	
Cost of Gas and Liquids					
Quarter ended June 30, 2006	105,473	56,179			161,652
Quarter ended June 30, 2005	79,753	32,302			112,055
Six months ended June 30, 2006	222,061	113,691			335,752
Six months ended June 30, 2005	158,022	60,381			218,403
Segment Margin					
Quarter ended June 30, 2006	20,734	10,717			31,451

Quarter ended June 30, 2005	21,768	3,527		25,295
Six months ended June 30, 2006	38,221	20,605		58,826
Six months ended June 30, 2005	19,596	5,963		25,559
Operating Expenses				
Quarter ended June 30, 2006	4,511	1,102		5,613
Quarter ended June 30, 2005	5,182	449		5,631
Six months ended June 30, 2006	9,369	2,249		11,618
Six months ended June 30, 2005	9,684	747		10,431
Depreciation and Amortization				

	Gathering and Processing	Transportation	Corporate	Eliminations	Consolidated Total
			(in thousands)		
Quarter ended June 30, 2006	4,416	3,072	204		7,692
Quarter ended June 30, 2005	4,126	970	123		5,219
Six months ended June 30, 2006	8,736	6,059	376		15,171
Six months ended June 30, 2005	8,192	1,944	246		10,382
Assets					
June 30, 2006	339,218	306,914	18,429		664,561
December 31, 2005	342,740	291,998	19,586		654,324
Expenditures for Long-Lived Assets					
Six months ended June 30, 2006	23,035	22,865	856		46,756
Six months ended June 30, 2005	520	21,583	192		22,295

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

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	(in thousands)			
Total segment margin (from above)	$ 31,451	$ 25,295	$ 58,826	$ 25,559
Operating expenses	5,613	5,631	11,618	10,431
General and administrative	5,820	3,688	10,628	6,053
Management services termination fee			9,000	
Depreciation and amortization	7,692	5,219	15,171	10,382
Operating income (loss)	12,326	10,757	12,409	(1,307)
Interest expense, net	(6,753)	(5,018)	(13,193)	(8,207)
Other income and deductions, net	71	49	158	108
Net income (loss) from continuing operations	$ 5,644	$ 5,788	$ (626)	$ (9,406)

10. Equity-Based Compensation

On December 12, 2005, the compensation committee of the board of directors of Regency GP LLC approved a long-term incentive plan (LTIP) for the Partnership s employees, directors and consultants covering an aggregate of 2,865,584 common units. Awards under the LTIP have been made since completion of the Partnership s IPO. LTIP awards generally vest on the basis of one-third of the award each year. The options have a maximum contractual term, expiring ten years after the grant date.

As of June 30, 2006, grants have been made in the amount of 432,500 restricted common units and 749,800 common unit options with weighted average grant-date fair values of $20.46 per unit and $1.20 per option. The options were valued with the Black-Scholes Option Pricing Model assuming 15 percent volatility in the unit price, a ten year term, a strike price equal to the grant-date price per unit, a distribution per unit of $1.40 per year, a risk-free rate of 4.25 percent, and an average exercise of the options of four years after vesting is complete. The assumption that employees will, on average, exercise their options four years from the vesting date is based on the average of the mid-points from vesting to expiration of the options. In aggregate, outstanding awards represent 1,164,000 potential common units.

The Partnership will make distributions to non-vested restricted common units on a one-for-one ratio with the per unit distributions paid to common units. Restricted common units are subject to contractual restrictions which lapse over time. Upon the vesting and exercise of the common unit options, the Partnership intends to settle these obligations with common units. Accordingly, the Partnership expects to recognize an aggregate of $9,243,000 of compensation expense related to the grants under LTIP, or $3,081,000 for each of the three years of the vesting period for such grants.

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Common Unit Options	Units	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term in Years	Aggregate Intrinsic Value* (in thousands)
Outstanding at December 31, 2005				
Granted	749,800	$ 20.30		
Exercised				
Forfeited or expired	(18,300)	20.00		
Outstanding at June 30, 2006	731,500	$ 20.31	9.6	$ 1,239
Exercisable at June 30, 2006				

* 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 June 30, 2006.

Restricted (Nonvested) Units	Units	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2005		
Granted	432,500	$ 20.46
Forfeited		
Outstanding at June 30, 2006	432,500	$ 20.46

11. Subsequent Events

Partner Distributions On July 27, 2006, the Partnership declared a distribution of $0.35 per common and subordinated unit, payable to unitholders of record as of August 7, 2006. The distribution will be paid on August 14, 2006.

Pending Acquisition of TexStar Field Services, L.P. On July 12, 2006, the Partnership entered into a definitive Contribution Agreement (the Contribution Agreement) with HMTF Gas Partners II, L.P. (HMTF Gas Partners), an affiliate of HM Capital Partners, pursuant to which the Partnership has agreed to acquire all the outstanding equity of TexStar Field Services, L.P. and its general partner, TexStar GP, LLC (together, TexStar) from HMTF Gas Partners (the TexStar Acquisition). TexStar owns and operates natural gas gathering, treating and processing assets located in

South and East Texas. The Partnership will pay approximately $350,000,000 for TexStar.

The purchase price for the TexStar Acquisition will be paid by (1) the issuance of 5,173,189 Class B common units of the Partnership to HMTF Gas Partners and (2) the payment of $235,000,000 in cash less TexStar s outstanding bank debt. This cash payment will be financed out of the proceeds of the Partnership s bank credit facility discussed below. All amounts paid are subject to customary adjustments at closing. The Class B Common Units issuable in the TexStar Acquisition will not be entitled to participate in Partnership distributions until they are convertible into common units on a one-for-one basis after the record date for the Partnership s cash distribution for the fourth quarter of 2006.

In connection with the TexStar Acquisition, BlackBrush Oil & Gas, L.P. (BlackBrush), an affiliate of TexStar that will be retained by HMTF Gas Partners and is not part of the TexStar Acquisition, will prior to the closing, enter into an agreement providing for the long term dedication to TexStar of the production from its leases.

Because the TexStar Acquisition is a transaction between commonly controlled entities, the Partnership will account for the transaction in a manner similar to a pooling of interests. Under pooling of interest accounting, the TexStar Acquisition will reflect historical balance sheet data for both the Partnership and TexStar instead of reflecting the fair market value of TexStar s assets and liabilities. Further, as a result of pooling of interest accounting, certain transaction costs that would normally be capitalized will be expensed.

The Partnership has received a bank facility commitment (the Bank Facility Commitment) from UBS Securities LLC, Wachovia Bank, National Association, and Citicorp USA, Inc. to provide a credit facility in the amount of $850,000,000 to be used to fund the cash portion of the consideration, to refinance debt assumed, to refinance bank debt currently outstanding of $389,750,000 and to provide an expanded revolving credit facility.

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The parties have made customary representations, warranties, covenants and agreements in the Contribution Agreement. Completion of the TexStar Acquisition is subject to various customary closing conditions, including (1) receipt of antitrust clearance and required third-party consents, (2) consummation of the debt financing contemplated by the Bank Facility Commitment and (3) the absence of any event that has or could reasonably be expected to have a material adverse effect on TexStar or the Partnership.

The Contribution Agreement is subject to termination: (1) by mutual agreement of the parties, (2) by either party, if the TexStar Acquisition has not been completed by September 5, 2006, subject to extension by either party to October 5, 2006 if antitrust clearance has not been obtained by September 5, 2006, (3) by either party, if the other party has (subject to the right to cure) breached any representation, warranty or covenant such that a closing condition would not be satisfied, (4) by the Partnership, if any event occurs that has or could reasonably be expected to have a material adverse effect on TexStar, and (5) by HMTF Gas Partners, if any event occurs that has or could reasonably be expected to have a material adverse effect on the Partnership.

Hicks Muse Equity Fund V, L.P. (Fund V) and its affiliates own indirectly approximately 53 percent of the limited partner units, and, through HM Capital Partners, controls, Regency GP LP, the general partner of the Partnership (the General Partner). Fund V also controls, through HM Capital Partners, HMTF Gas Partners. These affiliations created a conflict of interest in the General Partner. In recognition of that conflict, the board of directors of Regency GP LLC, the general partner of the General Partner, submitted the proposed TexStar Acquisition for resolution of the conflict to the Conflicts Committee of the board of directors, a committee of independent directors. Acting pursuant to provisions of the partnership agreement of the Partnership, the Conflicts Committee reviewed the transaction and performed procedures sufficient to conclude the transaction was fair to the Partnership, approved the transaction and recommended approval of the transaction by the full board of directors.

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

Overview

We are a Delaware limited partnership formed to capitalize on opportunities in the midstream sector of the natural gas industry. We are committed to providing high quality services to our customers and to delivering sustainable returns to our investors in the form of distributions and unit price appreciation.

We own and operate five major natural gas gathering systems and four active processing plants in north Louisiana, west Texas and the mid-continent region of the United States. We are engaged in gathering, processing, marketing and transporting natural gas and natural gas liquids, or NGLs. We also own and operate an intrastate natural gas pipeline in north Louisiana.

On February 3, 2006, we offered and sold 13,750,000 common units, representing a 35.3 percent limited partner interest in the Partnership, in our initial public offering at a price of $20.00 per unit. Total proceeds from the sale of the units were $275,000,000, before offering costs and underwriting commissions. Our common units began trading on the NASDAQ National Market under the symbol RGNC. See our annual report on Form 10-K for additional information on our initial public offering and the underwriters partial execution of their over allotment option.

On July 12, 2006, the Partnership entered into a definitive contribution agreement to acquire TexStar Field Services, L.P. for approximately $350,000,000. See Note 11, Subsequent Events, for further discussion.

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

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

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

Our management uses a variety of financial and operational measurements to analyze our performance. We review these measures on a monthly basis for consistency and trend analysis. These measures include volumes, total segment margin and operating expenses on a segment basis.

Volumes. As a result of naturally occurring production declines, we must continually obtain new supplies of natural gas to maintain or increase throughput volumes on our gathering and processing systems. Our ability to maintain existing supplies of natural gas and obtain new supplies is impacted by (1) the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to our pipelines, (2) our ability to compete for volumes from successful new wells in other areas and (3) our ability to obtain natural gas that has been released from other commitments. We routinely monitor producer activity in the areas served by our gathering and processing systems to pursue new supply opportunities.

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

Total Segment Margin. Segment margin from Gathering and Processing, together with segment margin from Transportation comprise Total Segment Margin. We use Total Segment Margin as a measure of performance.

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

We calculate our Transportation segment margin as revenue generated by fee income as well as, in those instances in which we purchase and sell gas for our account, gas sales revenue minus the cost of natural gas that we purchase and transport. Revenue

primarily includes fees for the transportation of pipeline-quality natural gas and sales of natural gas transported for our account. Most of our segment margin is fee-based with little or no commodity price risk. In those cases in which we purchase and sell gas for our account, we generally purchase pipeline-quality natural gas at a pipeline inlet price adjusted to reflect our transportation fee and we sell that gas at the pipeline outlet. In those cases, the difference between the purchase price and the sale price customarily exceeds the economic equivalent of our transportation fee.

The following table reconciles the non-GAAP financial measure, total segment margin, to its most directly comparable GAAP measure, net income (loss).

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(in thousands)			
Net income (loss)	$ 5,644	$ 6,482	$ (626)	$ (8,659)
Add (deduct):				
Operating expenses	5,613	5,631	11,618	10,431
General and administrative	5,820	3,688	10,628	6,053
Management services termination fee			9,000	
Depreciation and amortization	7,692	5,219	15,171	10,382
Interest expense, net	6,753	5,018	13,193	8,207
Other income and deductions, net	(71)	(49)	(158)	(108)
Discontinued operations		(694)		(747)
Total segment margin (1)	$ 31,451	$ 25,295	$ 58,826	$ 25,559

(1) The three and six month periods ended June 30, 2005 include approximately $5,005 and ($13,039) of unrealized gains (losses) on commodity hedging transactions.

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

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

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

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

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

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

EBITDA should not be considered an alternative to net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. EBITDA is the starting point in determining cash available for distribution, which is an important non-GAAP financial measure for a publicly traded master limited partnership.

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The following table reconciles the non-GAAP financial measure, EBITDA, to its most directly comparable GAAP measures, net income (loss) and net cash flows provided by operating activities.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(in thousands)			
Net cash flows provided by operating activities	$ 18,395	$ 7,665	$ 18,000	$ 12,571
Add (deduct):				
Depreciation and amortization	(7,766)	(5,502)	(15,398)	(11,059)
Risk management portfolio value changes	621	3,988	811	(13,337)
Unit based compensation expenses	(775)		(1,089)	
Gain on the sale of Regency Gas Treating LP assets		626		626
Accounts receivable	5,120	(2,350)	(8,631)	(4,267)
Other current assets	763	1,171	20	399
Accounts payable and accrued liabilities	(7,148)	1,638	11,751	5,972
Accrued taxes payable	(292)	(167)	(471)	(287)
Other current liabilities	120	(604)	735	574
Proceeds from early termination of interest rate swap	(3,550)		(3,550)	
Other assets	156	17	(2,804)	149
Net income (loss)	$ 5,644	$ 6,482	$ (626)	$ (8,659)
Add:				
Interest expense, net	6,753	5,018	13,193	8,207
Depreciation and amortization	7,692	5,219	15,171	10,382
EBITDA (1)	$ 20,089	$ 16,719	$ 27,738	$ 9,930

(1) The three and six month periods ended June 30, 2005 include approximately $5,005 and ($13,039) of unrealized gains (losses) on commodity hedging transactions.

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Cash Distributions

On May 15, 2006 the Partnership paid a distribution of $0.2217 per common and subordinated unit. The distribution constitutes the minimum quarterly distribution of $0.35 (or $1.40 per year), prorated for the period in the first quarter of 2006 since the Partnership s February 3, 2006 initial public offering.

On July 27, 2006, the Partnership declared a distribution of $0.35 per common and subordinated unit, payable to unitholders of record as of August 7, 2006. The distribution will be paid on August 14, 2006, and constitutes the minimum quarterly distribution of $0.35 (or $1.40 per year).

Results of Operations

The results of operations for the three and six months ended June 30, 2006 were significantly affected by the following matters, which are discussed in more detail under the captions below:

Transportation segment volumes and segment margin increased significantly as the third phase of the Regency Intrastate Enhancement Project completed its first six months of operation. Through August 1, 2006, we have signed definitive agreements for 556,800 MMBtu/d of firm transportation on the Regency Intrastate Pipeline system, of which 444,647 MMBtu/d was utilized

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in July 2006. During the month of July 2006 we provided 90,894 MMBtu/d of interruptible transportation. The volume and segment margin delivered by our transportation segment in the three months ended March 31, 2006 was, however, adversely affected by delayed pipeline interconnections and pipeline pressure issues on the part of certain customers and downstream markets. All interconnection issues were resolved during the first quarter. Beginning in May 2006, we were able to manage the pressure issues so that their impact on operations was mitigated, and we have begun implementing plans that will effectively resolve the pipeline pressure issues and ultimately expand the designed capacity of the pipeline to 910,000 Mcf/d by the fourth quarter of 2006.

In the three months ended March 31, 2006, we recorded a one-time charge of $9,000,000 as a termination fee in connection with the termination of two long-term management services contracts, which amount was paid out of the proceeds of our IPO.

The following are matters that may affect our future results of operations:

Because our hedging program locks in more favorable pricing in 2006 as compared to 2005, we expect to earn higher gathering and processing segment margins.

We currently expect to spend approximately $74,000,000 for organic growth capital expenditures in 2006, including projects approved during the second quarter by our Board of Directors totaling approximately $48,000,000. The new projects are expected to be operational in the second half of 2006. (See Capital Requirements)

As previously disclosed, a gathering contract with one of our suppliers representing over 10 percent of the volume in west Texas will expire in August 2006 and will not be renewed. The Partnership compared the book value of our west Texas assets to expected future cash flows and recorded no impairment.

Three Months Ended June 30, 2006 vs. Three Months Ended June 30, 2005

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

	Three Months Ended June 30,			
	2006	**2005**	**Change**	**Percent**
	(in thousands except volume data)			
Revenues (a)	$ 193,103	$ 137,350	$ 55,753	41%
Cost of gas and liquids	161,652	112,055	(49,597)	(44)
Total segment margin	31,451	25,295	6,156	24
Operating expenses	5,613	5,631	18	0
General and administrative	5,820	3,688	(2,132)	(58)
Depreciation and amortization	7,692	5,219	(2,473)	(47)
Operating income	12,326	10,757	1,569	15
Interest expense, net	(6,753)	(5,018)	(1,735)	(35)
Other income and deductions, net	71	49	22	45
Net income from continuing operations	5,644	5,788	(144)	(2)
Discontinued operations		694	(694)	n/m

Net income	$ 5,644	$ 6,482	$ (838)	(13)%
System inlet volumes (MMbtu/d) (b)	874,184	551,571	322,613	58%
Processing volumes (MMbtu/d) (c)	253,260	267,394	(14,134)	(5)

(a) The three month period ended June 30, 2005 includes approximately $5,005 of unrealized gains on commodity hedging transaction.
(b) System inlet volumes include total volumes taken into our gathering and processing and transportation systems.
(c) On August 1, 2005, we ceased operations at our Lakin processing plant, contracting with a third party to provide processing services for volumes previously processed at the Lakin facility. On May 1, 2006, we commenced operations at our Elm Grove processing plant.

n/m = not meaningful

Net Income Net income for the three months ended June 30, 2006 decreased $838,000 compared with the three months ended June 30, 2005. Total segment margin increased $6,156,000 primarily due to increased segment margin in the transportation segment of $7,190,000. Partially offsetting this increase was decreased segment margin of $1,034,000 in the gathering and processing segment, driven by a decrease in net unrealized gains of $3,873,000 from risk management activities related to mark-to-market accounting. The increase in transportation segment margin is attributable to the completion of our Regency Intrastate Enhancement Project at the end of 2005. The remaining price and volume variances in total segment margin and segment margin are discussed below.

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

	Three Months Ended June 30,			
	2006	2005	Change	Percent
	(in thousands except volume data)			
Segment Financial and Operating Data:				
Gathering and Processing Segment				
Financial data:				
Segment margin	$ 20,734	$ 21,768	$ (1,034)	(5)%
Operating expenses	4,511	5,182	671	13
Operating data:				
Throughput (MMbtu/d) (1)	291,492	306,263	(14,771)	(5)
NGL gross production (Bbls/d)	14,333	15,028	(695)	(5)
Transportation Segment				
Financial data:				
Segment margin	$ 10,717	$ 3,527	$ 7,190	204%
Operating expenses	1,102	449	(653)	(145)
Operating data:				
Throughput (MMbtu/d)(2)	582,692	245,309	337,383	138

(1) New well connections in west Texas over the last twelve months have not fully offset natural declines in production. The net throughput loss, however, has been largely concentrated in low margin contracts, and has been partially offset by net gains in production in the north Louisiana region.
(2) Excludes 10,440 MMBtu/d which flowed through both the transportation and the gathering and processing segments in 2006. Also excludes unused firm transportation of 86 MMbtu/d.

Segment Margin Total segment margin for the three months ended June 30, 2006 increased to $31,451,000 from $25,295,000 for the corresponding period in 2005. Transportation segment margin increased $7,190,000 primarily attributable to the Regency Intrastate Enhancement Project.

Gathering and processing segment margin for the three months ended June 30, 2006 decreased to $20,734,000 from $21,768,000 for the three months ended June 30, 2005. The elements of this decrease are as follows:

a decrease of $3,873,000 attributable to non-cash gains in the fair market value of derivative contracts;

an increase of $1,889,000 in segment margin attributable to increased gross margins resulting from more favorable pricing of executed hedges;

an increase of $1,576,000 in segment margin that is attributable to higher average margins on processed volumes;

an increase of $204,000 resulting from additional marketing activities surrounding NGL production; and

a decrease of $830,000 attributable to reduced throughput volumes.

Transportation segment margin for the three months ended June 30, 2006 increased to $10,717,000 from $3,527,000 for the three months ended June 30, 2005, a 204 percent increase. The elements of this increase are as follows:

an increase of $4,809,000 attributable to increased throughput volumes;

an increase of $1,131,000 resulting from an average of 86,000 MMBtu/d of unused incremental firm transportation contracted by several shippers;

an increase of $697,000 resulting from increased marketing activities around the expanded system; and

an increase of $553,000 resulting from lower average transportation fees.

General and Administrative General and administrative expense increased to $5,820,000 in the three months ended June 30, 2006 from $3,688,000 for the comparable period in 2005, a 58 percent increase. This increase was primarily attributable to the accrual of non-cash expense associated with our new long-term incentive plan of $775,000 in the three months ended June 30, 2006; higher salary expenses of $693,000, associated with hiring key personnel to assist in achieving our strategic objectives; and acquisition related expenditures of $684,000 in the three months ended June 30, 2006 related to the acquisition of TexStar Field Services, L.P. The increases in general and administrative expenses are consistent with the level that we had anticipated as a result of becoming a publicly traded entity.

Depreciation and Amortization Depreciation and amortization increased to $7,692,000 in the three months ended June 30, 2006 from $5,219,000 for the corresponding period in 2005, representing a 47 percent increase. Depreciation expense increased $2,102,000 primarily due to the higher depreciable basis of our transportation system with the completion of our Regency Intrastate Enhancement Project at the end of 2005.

Interest Expense, Net Interest expense, net increased $1,735,000, or 35 percent, in the three months ended June 30, 2006 compared to the three months ended June 30, 2005. Of the increase, $2,347,000 is due to higher levels of borrowings primarily associated with growth capital expenditures, primarily offset by $563,000 of reduced unrealized hedging losses recorded in interest expense for the three month period ended June 30, 2006.

Discontinued Operations On May 2, 2005, we sold all of the Cardinal assets, together with certain related assets, for $6,000,000. The results of Cardinal are presented as discontinued operations, and we recorded a gain on the sale of $626,000 in the three months ended June 30, 2005.

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Six Months Ended June 30, 2006 vs. Six Months Ended June 30, 2005

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

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005	Change	Percent
	(in thousands except volume data)			
Revenues (a)	$ 394,578	$ 243,962	$ 150,616	62%
Cost of gas and liquids	335,752	218,403	(117,349)	(54)
Total segment margin	58,826	25,559	33,267	130
Operating expenses	11,618	10,431	(1,187)	(11)
General and administrative	10,628	6,053	(4,575)	(76)
Management services termination fee (b)	9,000		(9,000)	n/m
Depreciation and amortization	15,171	10,382	(4,789)	(46)
Operating income (loss)	12,409	(1,307)	13,716	n/m
Interest expense, net	(13,193)	(8,207)	(4,986)	(61)
Other income and deductions, net	158	108	50	46
Net loss from continuing operations	(626)	(9,406)	8,780	93
Discontinued operations		747	(747)	n/m
Net loss	$ (626)	$ (8,659)	$ 8,033	93%
System inlet volumes (MMbtu/d) (c)	813,803	518,264	295,539	57%
Processing volumes (MMbtu/d) (d)	220,767	256,633	(35,866)	(14)

(a) The six month period ended June 30, 2005 includes $13,039 of unrealized losses on commodity hedging transactions.

(b) The management

services termination fee was paid with proceeds from our IPO.

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

(d) On August 1, 2005, we ceased operations at our Lakin processing plant, contracting with a third party to provide processing services for volumes previously processed at the Lakin facility. On May 1, 2006, we commenced operations at our Elm Grove processing plant. New well connections in west Texas over the last twelve months have not fully offset natural declines in production. The net throughput loss, however, has been largely concentrated in low margin contracts, and has been partially offset by net gains in production in the north Louisiana region.

n/m = not meaningful

Net Loss Net loss for the six months ended June 30, 2006 decreased $8,033,000 compared with the six months ended June 30, 2005. Total segment margin increased $33,267,000 or 130 percent. The segment margin for the six months ended June 30, 2005 includes an unrealized loss of $13,039,000 from risk management activities related to mark-to-market accounting. Including the $13,039,000 unrealized loss, gathering and processing segment margin increased $18,625,000 and transportation segment margin increased $14,642,000. The increase in transportation segment margin is attributable to the completion of our Regency Intrastate Enhancement Project at the end of 2005. The remaining price and volume variances in total segment margin and segment margin are discussed below.

Earnings for the six months ended June 30, 2006 were adversely affected by a one-time $9,000,000 charge incurred as a termination fee in connection with the termination of two long-term management services contracts. The contracts were terminated in connection with our IPO and the payment of this charge was made out of the proceeds from the IPO.

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

	Six Months Ended June 30, 2006	2005	Change	Percent
	(in thousands except volume data)			
Segment Financial and Operating Data:				
Gathering and Processing Segment				
Financial data:				
Segment Margin	$ 38,221	$ 19,596	$ 18,625	95%
Operating expenses	9,369	9,684	315	3
Operating data:				
Throughput (MMbtu/d) (1)	295,583	308,490	(12,907)	(4)
NGL gross production (Bbls/d)	14,099	15,275	(1,176)	(8)
Transportation Segment				
Financial data:				
Segment Margin	$ 20,605	$ 5,963	$ 14,642	246%
Operating expenses	2,249	747	(1,502)	(201)
Operating data:				
Throughput (MMbtu/d) (2)	518,220	209,774	308,446	147

(1) New well connections in west Texas over the last twelve months have not fully offset natural declines in production. The net throughput loss, however, has been largely concentrated in low margin contracts, and has been partially offset by net gains in production in the north Louisiana region.

(2) Excludes 5,249 MMBtu/d which flowed through both the

transportation and the gathering and processing segments in 2006. Also excludes unused firm transportation of 81 MMbtu/d.

Segment Margin Total segment margin for the six months ended June 30, 2006 increased to $58,826,000 from $25,559,000 for the corresponding period in 2005. The $33,267,000 increase in total segment margin includes a $13,039,000 unrealized loss from risk management activities related to mark-to-market accounting in 2005. For further information, please see Critical Accounting Policies Risk Management Activities.

Gathering and processing segment margin for the six months ended June 30, 2006 increased to $38,221,000 from $19,596,000 for the six months ended June 30, 2005. The elements of this increase are as follows:

- an increase of $14,680,000 attributable to a reduction in non-cash losses in the fair market value of derivative contracts;
- an increase of $3,756,000 in segment margin attributable to increased hedged gross margins resulting from more favorable pricing of executed hedges;
- an increase of $1,576,000 in segment margin that is attributable to higher average margins on processed volumes;
- an increase of $204,000 resulting from additional marketing activities surrounding NGL production; and
- a decrease of $1,429,000 in segment margin attributable to reduced throughput volumes.

Transportation segment margin for the six months ended June 30, 2006 increased to $20,605,000 from $5,963,000 for the comparable period in 2005, a 246 percent increase. The elements of this increase are as follows:

- an increase of $8,461,000 attributable to increased throughput volumes;
- an increase of $2,797,000 resulting from increased marketing activities around the expanded system;
- an increase of $2,035,000 resulting from an average of 81,000 MMBtu/d of unused incremental firm transportation contracted by several shippers; and
- an increase of $1,451,000 resulting from higher average transportation fees.

During the first quarter of 2006, one of our firm transport customers did not use all of the transportation capacity to which it was entitled due to pressure losses on their gathering system. In the second quarter of 2006, these pressure issues were alleviated by the seasonal demand for electricity. For a long-term solution, the customer has informed us of their intent to add compression in the third and fourth quarters of 2006 so that they can transport more gas on our pipeline. Compounding the first quarter 2006 problem was an interstate pipeline s loss of two compressor turbines causing the pressure at our interconnect to exceed historical parameters significantly. The operators of the interstate pipeline have informed us that they expect the compressor turbines to return to service in the latter part of the fourth quarter of 2006. The addition of compression by our customer, together with the reconfiguration of their gathering system will allow them to deliver gas into our pipeline even if the interstate pipeline operates at their maximum allowable operating pressure.

To the extent that inlet pressure at the south westernmost point on the Gulf States Transmission Corporation (GSTC) pipeline exceeds a certain pressure that is determined by a competitor, the competitor can divert gas into its own system. In turn, this reduces the volume of gas coming into our north Louisiana intrastate pipeline. We have signed firm transportation contracts on GSTC with some of the gas producers whose deliveries of gas into GSTC are affected by our competitor. We plan to reduce significantly the relevant inlet pressure by installing additional pipeline looping on our pipeline and by adding compression. The additional pipeline looping went into service in early August 2006 and the compression is scheduled for installation in the fourth quarter of 2006.

Operating Expenses Operating expenses for the six months ended June 30, 2006 increased to $11,618,000 from $10,431,000 for the corresponding period in 2005, representing an 11 percent increase. This increase resulted in part from an increase in non-income taxes of $1,034,000, mainly associated with property taxes on our Regency Intrastate Enhancement Project in our transportation segment. The remaining $153,000 is attributable to employee expenses, utilities for gathering and processing, overtime related to maintenance events in the north Louisiana region, and higher employee related costs partially offset by lower contractor expenses.

General and Administrative General and administrative expense increased to $10,628,000 in the six months ended June 30, 2006 from $6,053,000 for the comparable period in 2005. This increase was primarily attributable to higher employee-related expenses of $2,111,000, including higher salary expense associated with hiring key personnel to assist in achieving our strategic objectives. Also contributing to the increase was the accrual of non-cash expense associated with our new long-term incentive plan of $1,089,000 in the six months ended June 30, 2006. Further contributing to the increase were increased professional and consulting expenses of $434,000, consisting primarily of audit fees and consulting fees for Sarbanes-Oxley compliance support. We do not expect to incur significant external Sarbanes-Oxley compliance support expense during the remainder of 2006. The six month period ended June 30, 2006 includes acquisition expenditures of $684,000 related to the TexStar acquisition. Other general and administrative expenses increased $351,000 primarily due to outside directors fees and expenses in the six months ended June 30, 2006 that were not present in the six months ended June 30, 2005. Rent expense increased $117,000 due to the leasing of additional office space in the second half of 2005. Insurance expense increased $115,000 due to higher costs associated with directors and officers insurance.

The increases in operating expenses and general and administrative expenses are consistent with the level that we had anticipated as a result of becoming a publicly traded entity.

Depreciation and Amortization Depreciation and amortization increased to $15,171,000 in the six months ended June 30, 2006 from $10,382,000 for the corresponding period in 2005, representing a 46 percent increase. Depreciation expense increased primarily due to the higher depreciable basis of our transportation system with the completion of our Regency Intrastate Enhancement Project at the end of 2005.

Interest Expense, Net Interest expense, net increased $4,986,000, or 61 percent, in the six months ended June 30, 2006 compared to the six months ended June 30, 2005. Of the increase, $4,430,000 is due to higher levels of borrowings primarily associated with our Regency Intrastate Enhancement Project and growth capital expenditures, $142,000 is attributable to higher rates and the remaining $414,000 is attributable to an unrealized gain recorded in the prior period when we used mark-to-market accounting for interest rate swaps.

Discontinued Operations On May 2, 2005, we sold all of the Cardinal assets, together with certain related assets, for $6,000,000. The results of Cardinal are presented as discontinued operations, and we recorded a gain on the sale of $626,000 in the six months ended June 30, 2005.

Critical Accounting Policies

Conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the financial statements and notes. Although these estimates are based on management s best available knowledge of current and expected future events, actual results could be different from those estimates. We believe that the following are the more critical judgment areas in the application of our accounting policies that currently affect our financial condition and results of operations.

Revenue and Cost of Sales Recognition. We record revenue and cost of sales on the gross basis for those transactions where we act as the principal and take title to gas that we purchase for resale. When our customers pay us a fee for providing a service such as gathering or transportation we record the fees separately in revenues. In March 2006, the Partnership implemented a process for estimating certain revenue and expenses as actual amounts are not confirmed until after the financial closing process due to the standard settlement dates in the gas industry. Estimated revenues are calculated using actual pricing and nominated volumes. In the subsequent production month, we reverse the accrual and record the actual results. Prior to the settlement date, we record actual operating data to the extent available, such as actual operating and maintenance and other expenses. We do not expect actual results to differ materially from our estimates.

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

From the inception of our hedging program in December 2004 through June 30, 2005, we used mark-to-market accounting for our commodity and interest rate swaps as well as for crude oil puts. We recorded realized gains and losses on hedge instruments monthly based upon the cash settlements and the expiration of option premiums. The settlement amounts varied due to the volatility in the commodity market prices throughout each month.

Effective July 1, 2005, we elected hedge accounting under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities , as amended and determined the then current hedges outstanding, excluding crude oil put options, qualified for hedge accounting whereby the unrealized changes in fair value are recorded in other comprehensive income (loss) to the extent the hedge is effective. Prior to July 1, 2005, we had recorded unrealized losses in the fair market value of commodity-related derivative contracts and unrealized gains on an interest rate swap into revenues and interest expense, net respectively

Equity Based Compensation. On December 12, 2005, the compensation committee of the board of directors of Regency GP LLC approved a long-term incentive plan (LTIP) for the Partnership s employees, directors and consultants covering an aggregate of 2,865,584 common units. Awards under the LTIP have been made since the completion of the Partnership s IPO. LTIP awards generally vest on the basis of one-third of the award each year. The options have a maximum contractual term, expiring ten years after the grant date.

As of June 30, 2006, grants have been made in the amount of 432,500 restricted common units and 749,800 common unit options with weighted average grant-date fair values of $20.46 per unit and $1.20 per option. The options were valued with the Black-Scholes Option Pricing Model assuming 15 percent volatility in the unit price, a ten year term, a strike price equal to the grant-date price per unit, a distribution per unit of $1.40 per year, a risk-free rate of 4.25 percent, and an average exercise of the options of four years after vesting is complete. The assumption that option exercises, on average, will be four years from the vesting date is based on the average of the mid-points from vesting to expiration of the options. In aggregate, outstanding awards represent 1,164,000 potential common units.

The Partnership will make distributions to non-vested restricted common units on a one-for-one ratio with the per unit distributions paid to common units. Restricted common units are subject to contractual restrictions which lapse over time. Upon the vesting and exercise of the common unit options, the Partnership intends to settle these obligations with common units. Accordingly, the Partnership expects to recognize an aggregate of $9,243,000 of compensation expense related to the grants under LTIP, or $3,081,000 for each of the three years of the vesting period for such grants. We adopted SFAS 123(R) Share-Based Payment in the first quarter of 2006 which resulted in no change in accounting principles as no LTIP awards were outstanding during 2005.

Other Matters

El Paso Claims Under the purchase and sale agreement, or PSA, pursuant to which we purchased our north Louisiana and Midcontinent assets from affiliates of El Paso Field Services, LP, or El Paso, in 2003, El Paso indemnified us (subject to a limit of

$84,000,000) for environmental losses as to which El Paso was deemed responsible. Of the cash escrowed for this purpose at the time of sale, $5,654,000 remained in escrow at June 30, 2006. Upon completion of a Phase II investigation of various assets so acquired (the Phase II Assets), we notified El Paso of indemnity claims of approximately $5,400,000 for environmental liabilities. In related discussions, El Paso denied all but $280,000 of these claims (which it evaluated at $75,000 and agreed to cure itself). In these discussions, we agreed, at El Paso s request, to install permanent monitoring wells at the facilities where ground water impacts were indicated by the Phase II activities. We also agreed to withdraw our claims with respect to all but seven of the Phase II Assets (which comprise those subject to accepted claims).

A Final Site Investigations Report with respect to those Phase II Assets has since been prepared and issued based on information obtained from the permanent monitoring wells. Environmental issues exist with respect to four facilities, including the two subject to accepted claims and two of the Partnership s processing plants. The estimated remediation costs associated with the processing plants aggregate $2,750,000. The Partnership believes that any of its obligations to remediate the properties is subject to the indemnity under the El Paso PSA, and intends to reinstate the claims for indemnification for these plant sites.

Texas Tax Legislation In the three months ended June 30, 2006, the State of Texas passed legislation that imposes a margin tax on partnerships and master limited partnerships. We currently estimate that the effect of this legislation will not have a material effect on our results of operations, cash flows, or financial condition.

Liquidity and Capital Resources

Working Capital (Deficit). Working capital is the amount by which current assets exceed current liabilities and is a measure of our ability to pay our liabilities as they become due. During periods of growth capital expenditures, we experience working capital deficits when 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 twelve months, and so must be viewed differently from trade receivables and payables which settle over a much shorter span of time. These factors affect working capital but not our ability to pay bills as they come due.

Our working capital deficit was ($12,264,000) at June 30, 2006 and ($27,650,000) at December 31, 2005. The $15,386,000 net increase from December 31, 2005 to June 30, 2006 resulted primarily from:

a decrease in the excess of accounts payable over accounts receivable by $15,195,000 primarily attributable to a decrease of $12,075,000 in construction accounts payable related to the completion of our Regency Intrastate Enhancement Project;

a $2,814,000 increase in the net current liability valuation of our risk management contracts due to higher index NGL prices and the early termination of an interest rate swap, offset by increases in interest rates;

a $2,721,000 increase in cash and cash equivalents primarily due to $3,550,000 received for an early termination of an interest rate swap.

Cash Flows from Operations Net cash flows provided by operating activities increased $5,429,000, or 43 percent, in the six months ended June 30, 2006 compared to the corresponding period in 2005. The increase was primarily the result of a decrease in our net loss of $8,033,000 primarily due to increased segment margin related to the completion of our Regency Intrastate Enhancement project offset by a $9,000,000 payment to an affiliate of HM Capital. Also contributing to the increase in cash flows from operations was $3,550,000 cash received from the early termination of an interest rate swap and an increase of $4,339,000 of depreciation and amortization due to an increase in our depreciable basis in 2006 as compared to 2005. The six month period ended June 30, 2006 includes $1,089,000 in unit based compensation expense related to our long term incentive plan that was approved by the Board of Directors in December 2005. Offsetting these increases is the decreased impact of risk management activities of $14,148,000 due to the adoption of hedge accounting on July 1, 2005.

Cash Flows Used in Investing Activities Net cash flows used in investing activities increased $24,653,000, or 112 percent, in the six months ended June 30, 2006 compared to the six months ended June 30, 2005. The increase is primarily due to higher levels of capital expenditures related to the completion of our Regency Intrastate Enhancement Project and growth and maintenance capital expenditures.

Cash Flows Provided by Financing Activities Net cash flows provided by financing activities increased $22,595,000, or 254 percent, in the six months ended June 30, 2006 compared to the corresponding period in 2005. The increase is due to working capital and growth capital expenditures financed with additional borrowings under our credit facility and net proceeds related to our initial public offering, offset by partner distributions.

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Capital Requirements

Growth and Maintenance Capital Expenditures. In the six months ended June 30, 2006, we incurred $31,271,000 of growth capital expenditures and $3,410,000 of maintenance capital expenditures. Growth capital expenditures for the six months ended June 30, 2006 primarily relate to the completion of our Regency Intrastate Enhancement Project, a new 200 MMcf/d dewpoint control facility in Bossier Parish, Louisiana, additional gas compressors, approximately 16 miles of 24-inch pipeline and related compression associated with a scheduled loop of a western segment of our intrastate pipeline and approximately 6 miles of 12-inch pipeline in Lincoln Parish, Louisiana.

We expect to spend approximately $74,000,000 for organic growth capital expenditures in 2006 as compared to our estimate of $25,100,000 disclosed in our Annual Report on Form 10-K for the year ended December 31, 2005. Substantially all of the increased balance relates to new projects recently approved by our Board of Directors. These expenditures are for:

- approximately 16 miles of 24-inch pipeline and related compression associated with a scheduled loop of a western segment of our intrastate pipeline;
- a new 200 MMcf/d dewpoint control facility scheduled for installation on our intrastate pipeline in Webster Parish, Louisiana;
- the expansion of existing compression and gathering capacity to accommodate producers in Lincoln Parish, Louisiana; and
- the addition of standby compressor capacity.

We expect these new growth projects to be operational during the third and fourth quarters of 2006. We expect to fund these growth capital expenditures out of borrowings under our existing credit agreement.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are a net seller of NGLs, and as such our financial results are exposed to fluctuations in NGLs pricing. We have executed swap contracts settled against ethane, propane, butane and natural gasoline market prices, supplemented with crude oil put options. As a result, we have hedged approximately 95 percent of our expected exposure to NGL prices in 2006, approximately 90 percent in 2007, and approximately 60 percent in 2008. We continually monitor our hedging and contract portfolio and expect to continue to adjust our hedge position as conditions warrant.

The following table sets forth certain information regarding our non-trading NGL swaps outstanding at June 30, 2006. The relevant index price that we pay is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, as reported by the Oil Price Information Service (OPIS).

Period		Commodity	Notional Volume (MBbls)	We Pay	We Receive ($/gallon)	Fair Value (in thousands)
July 2006	December 2008	Ethane	925	Index	$ .55 - $ .58	$ (4,506)
July 2006	December 2008	Propane	811	Index	$ .66 - $ .93	(10,676)
July 2006	December 2008	Butane	438	Index	$ 1.03 - $1.12	(4,212)
July 2006	December 2008	Natural Gasoline	178	Index	$ 1.22 - $1.41	(2,245)
Total Fair Value						$ (21,639)

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

Notional	Strike Prices

Period		Commodity	Volume (MBbls)	($/BBL)	Fair Value (in thousands)
July 2006	December 2007	NYMEX West Texas Intermediate Crude	1,911	$ 30 - $36.50	$ 17

The following table sets forth certain information regarding our interest rate swaps:

Period		Interest Rate Swap Type	Notional Borrowings	We Pay	We Receive	Fair Value (in thousands)
July 2006	March 2007	Floating to Fixed	$200 million	3.95%	LIBOR	$ 2,372

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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 Managing GP, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rule 13a 15(e) and 15d 15(e) of the Exchange Act). Based on that evaluation, management, including the Chief Executive Officer and Chief Financial Officer of our Managing GP, concluded that our disclosure controls and procedures were effective as of June 30, 2006 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

In anticipation of becoming subject to the provisions of Section 404 of the Sarbanes-Oxley Act of 2002, we initiated in early 2005 a program of documentation, implementation and testing of internal control over financial reporting. This program will continue through this year and next, culminating with our initial Section 404 certification and attestation in early 2008. As of June 30, 2006, we have evaluated the effectiveness of our system of internal control over financial reporting, as well as changes therein, in compliance with Rule 13a-15 of the SEC s rules under the Securities Exchange Act and have filed the certifications with this report required by Rule 13a-14.

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

During the three months ended June 30, 2006, there has been no change in the Partnership s internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Partnership s internal control over financial reporting.

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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, 2005, 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. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

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

The information required for this item is provided in Note 1, Organization and Summary of Significant Accounting Policies, included in the Notes to the Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1, which information is incorporated by reference into this item.

Item 6. Exhibits

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

Exhibit 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 Section 1350 Certifications of Chief Executive Officer and Chief Financial Officer

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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
Vice President of Accounting and Finance
(Duly
Authorized Officer and Chief Accounting
Officer)

August 14, 2006

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