Regency Energy Partners LP
Form 10-Q
May 15, 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 March 31, 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	16-1731691
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1700 PACIFIC AVENUE, SUITE 2900 DALLAS, TX	75201
(Address of principal executive offices)	(Zip Code)

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

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

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

þ Yes o No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, 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 19,521,396 common units and 19,103,896 subordinated units outstanding as of May 1, 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, will, or help 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.

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements

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

	March 31, 2006	December 31, 2005
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 2,477	$ 3,669
Restricted cash	5,596	5,533
Accounts receivable, net of allowance of $169 in 2006 and $169 in 2005	65,031	78,782
Assets from risk management activities	2,431	1,717
Other current assets	3,207	3,950
Total current assets	78,742	93,651
Property, plant and equipment		
Gas plants and buildings	46,810	46,399
Gathering and transmission systems	402,090	397,481
Other property, plant and equipment	43,228	41,470
Construction - in - progress	23,309	16,738
Total property, plant and equipment	515,437	502,088
Less accumulated depreciation	(28,511)	(21,505)
Property, plant and equipment, net	486,926	480,583
Intangible and other assets		
Intangible assets, net of amortization	15,903	16,370
Goodwill	57,552	57,552
Long-term assets from risk management activities	2,008	1,333
Other, net of amortization on debt issuance costs of $422 in 2006 and $271 in 2005	1,871	4,835
Total intangible and other assets	77,334	80,090
TOTAL ASSETS	**$ 643,002**	**$ 654,324**
LIABILITIES & PARTNERS CAPITAL		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 65,777	$ 99,745
Escrow payable	5,596	5,533
Accrued taxes payable	2,445	2,266
Liabilities from risk management activities	7,595	11,312

Other current liabilities		1,830		2,445
Total current liabilities		83,243		121,301
Long term liabilities from risk management activities		4,570		4,895
Long-term debt		377,150		358,350
Commitments and contingencies				
Partners capital or member interest				
Member interest				180,740
Common unitholders (19,466 units outstanding at March 31, 2006)		90,015		
Subordinated unitholders (19,104 units outstanding at March 31, 2006)		90,072		
General partner		3,674		
Accumulated other comprehensive loss		(5,722)		(10,962)
Total partners capital		178,039		169,778
TOTAL LIABILITIES & PARTNERS CAPITAL	**$**	**643,002**	**$**	**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)

	Three Months Ended March 31, 2006	2005
REVENUE		
Gas sales	$ 138,780	$ 80,189
NGL sales	50,394	36,914
Gathering, transportation and other fees	10,382	5,464
Unrealized/realized gain/(loss) from risk management activities	(1,657)	(19,337)
Other	3,576	3,382
Total revenue	201,475	106,612
EXPENSE		
Cost of gas and liquids	171,321	104,112
Other cost of sales	2,780	2,237
Operating expenses	6,046	4,874
General and administrative	4,768	2,292
Management services termination fee	9,000	
Depreciation and amortization	7,477	5,161
Total operating expense	201,392	118,676
OPERATING INCOME (LOSS)	**83**	**(12,064)**
OTHER INCOME AND DEDUCTIONS		
Interest expense, net	(6,441)	(3,189)
Other income and deductions, net	88	60
Total other income and deductions	(6,353)	(3,129)
NET LOSS FROM CONTINUING OPERATIONS	**(6,270)**	**(15,193)**
DISCONTINUED OPERATIONS		
Income from operations of Regency Gas Treating LP		52
NET LOSS	**(6,270)**	**$ (15,141)**
Less:		
Net income through January 31, 2006	1,580	
Net loss for partners	**$ (7,850)**	

Allocation of net loss:		
Limited partners interest	$	(7,694)
General partner s interest		(156)
Net loss for partners		(7,850)
Basic and diluted net loss per limited partner unit	$	(0.20)
Weighted average number of limited partner units outstanding used for basic and diluted net loss per unit calculation		38,208

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)

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
OPERATING ACTIVITIES		
Net loss	**$ (6,270)**	**$ (15,141)**
Adjustments to reconcile net loss to net cash flows provided (used) by operations:		
Depreciation & amortization	7,628	5,557
Risk management portfolio valuation changes	(191)	17,325
Unit based compensation expenses	314	
Cash flows impacted by changes in current assets and liabilities:		
Accounts receivable	13,751	1,917
Other current assets	742	772
Accounts payable and accrued liabilities	(18,899)	(4,334)
Accrued taxes payable	179	120
Other current liabilities	12	(1,178)
Other assets	2,963	(132)
Other liabilities	(626)	
Net cash flows provided (used) by operating activities	**(397)**	**4,906**
INVESTING ACTIVITIES		
Capital expenditures	(28,421)	(4,324)
Cash outflows for acquisition by HM Capital		(5,808)
Net cash flows used in investing activities	**(28,421)**	**(10,132)**
FINANCING ACTIVITIES		
Repayments under credit facilities		(500)
Net borrowings under revolving credit facilities	18,800	5,000
Debt issuance costs	(151)	(51)
IPO proceeds, net of issuance costs	256,953	
Capital reimbursement to HM Capital	(195,757)	
Working capital distribution to HM Capital	(48,000)	
Offering costs	(4,219)	
Net proceeds from exercise of over allotment option	26,163	
Over allotment option net proceeds to HM Capital	(26,163)	
Net cash flows provided by financing activities	**27,626**	**4,449**

Net decrease in cash and cash equivalents		(1,192)		(777)
Cash and cash equivalents at beginning of period		**3,669**		**3,272**
Cash and cash equivalents at end of period	**$**	**2,477**	**$**	**2,495**
Supplemental cash flow information				
Interest paid	**$**	**6,251**	**$**	**3,793**
Non-cash capital expenditures in accounts payable	**$**	**15,069**	**$**	**102**

See accompanying notes to unaudited condensed consolidated financial statements.

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Regency Energy Partners LP
Condensed Consolidated Statement of Partners Capital
Unaudited
($ in thousands)

		Regency Energy Partners LP				
	Member Interest	Common Units	Subordinated Units	General Partner Interest	Accumulated Other Comprehensive Income	Total
Balance January 1, 2006	$ 180,740	$	$	$	$ (10,962)	$ 169,778
Comprehensive income through January 31, 2006						
Hedging gains or losses reclassified to earnings					616	616
Net change in fair value of cash flow hedges					2,581	2,581
Net income through January 31, 2006	1,580					1,580
Comprehensive income through January 31, 2006						4,777
Balance January 31, 2006	182,320					
Contribution of net investment to unit holders	(182,320)	89,337	89,337	3,646		
Proceeds from IPO, net of issuance costs		125,907	125,907	5,139		256,953
Net proceeds from exercise of over allotment option		26,163				26,163
Over allotment option net proceeds to HM Capital		(26,163)				(26,163)
Capital reimbursement to HM Capital Partners		(119,441)	(119,441)	(4,875)		(243,757)
Offering costs		(2,067)	(2,067)	(84)		(4,219)
Unit based compensation expenses		155	153	6		314
Comprehensive income from February 1, 2006 through March 31, 2006						
Net loss from February 1, 2006 through March 31, 2006		(3,876)	(3,817)	(157)		(7,850)
Hedging gains or losses reclassified to earnings					197	197
Net change in fair value of cash flow hedges					1,846	1,846
Comprehensive income (loss) from February 1, 2006 through March 31, 2006						(5,807)
Balance March 31, 2006	$	$ 90,015	$ 90,072	$ 3,674	$ (5,722)	$ 178,039

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, Business Operations and Summary of Significant Accounting Policies

Organization and Business Operations The unaudited condensed consolidated financial statements presented herein contain the results of Regency Energy Partners LP, a Delaware limited partnership (the 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).

Initial Public Offering On February 3, 2006, Regency Energy Partners LP offered and sold 13,750,000 common units, representing a 35.3% 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 million, 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) in exchange for 19,103,896 subordinated units representing a 49% limited partner interest in the Partnership; 5,353,896 common units representing a 13.7% limited partner interest in the Partnership; a 2% general partner interest in the Partnership; incentive distribution rights; and the right to reimbursement of approximately $196 million 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 approximately $196 million to Acquisition in reimbursement of its capital investment in the Predecessor and to replenish $48 million of working capital assets distributed to Acquisition immediately prior to the IPO; to pay $9 million to an affiliate of Acquisition to terminate two management services contracts; and to pay $22 million of underwriting commissions, structuring fees and other offering costs. In connection with the IPO, the Partnership incurred direct costs totaling $4.2 million 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.

Basis of Presentation 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, 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 unaudited financial information as of March 31, 2006 and for the three months ended March 31, 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 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.

The Partnership operates and manages its business as two reportable segments: a) gathering and processing, and b) transportation. (See Note 7).

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 revenue and certain expenses in an effort to improve the timeliness of its financial information. Therefore, the

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revenues and certain expenses presented on income statements for periods ending March 31, 2006 and later will include an estimate of the results of operations for the final month in each period.

Earnings Per Unit Earnings per unit presented on the statement of operations for the three months ended March 31, 2006 reflect only the earnings for the two 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. An aggregate of 1,016,500 potentially dilutive units related to the LTIP program (362,500 nonvested units and 654,000 unexercised options) have been excluded from diluted earnings per unit as the effect is antidilutive. 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 128 Earnings per Share.

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

Equity-Based Compensation The Partnership adopted SFAS 123(R) Share-Based Compensation 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 8 for further disclosures.

Comprehensive Loss - Comprehensive loss for the three months ending March 31, 2006 was $1.0 million. Comprehensive loss is the same as net loss for the three months ending March 31, 2005.

Risk Management Activities - As of March 31, 2006, $3.1 million of losses are expected to be reclassified into earnings from Other Comprehensive Income (loss) in the next twelve months.

2. Intangible Assets

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

	Permits and Licenses	**Customer Contracts**	**Total**
		($ in millions)	
Useful life (in years)	15	3 - 12	
Gross carrying amount at December 31, 2005	$11.9	$ 6.5	$18.4
Accumulated amortization at December 31, 2005	(0.9)	(1.2)	(2.1)
Net carrying amount at December 31, 2005	11.0	5.3	16.3
Accumulated amortization at March 31, 2006	(1.1)	(1.4)	(2.5)
Net carrying amount at March 31, 2006	$10.8	$ 5.1	$15.9

3. Long-Term Debt

Obligations under the Partnership s credit facility at March 31, 2006 and December 31, 2005 are as follows:

	March 31, 2006	**December 31, 2005**
	($ in millions)	
Term Loans	$ 308.4	$ 308.4
Revolving Loans	68.8	50.0
Long-term Debt	$ 377.2	$ 358.4
Total Facility Limit	$ 468.4	$ 468.4
Term Loans	(308.4)	(308.4)
Revolving Loans	(68.8)	(50.0)
Letters of Credit	(2.1)	(10.7)

Credit Available	$	89.1	$	99.3

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The outstanding balances of term debt and revolver debt under the Partnership s credit agreement bear interest at either LIBOR plus margin or at ABR 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 6.95% and 5.13% for the three months ended March 31, 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 March 31, 2006, the Partnership was in compliance with these covenants.

4. 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 by an environmental consultant engaged by the Predecessor in connection with the pre-acquisition due diligence process in 2004. The study noted that most of the identified environmental contamination had either been remediated or was being remediated by the previous owners or operators of the properties. The study estimated potential environmental remediation costs at specific locations at $1.9 million to $3.1 million. One premise of the study was that the responsibility for remediation of the matters included in the study rests with those previous owners or operators that are engaged in remediation activities relating to those matters. No governmental agency has required 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 matters identified in the study is remote. Separately, the Partnership acquired an environmental pollution liability insurance policy in connection with the acquisition to cover any undetected or unknown pollution discovered in the future. The policy covers clean-up costs and damages to third parties and has a 10-year term (expiring in 2014) with a $10 million 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 million) for environmental losses as to which El Paso was deemed responsible. Of the cash escrowed for this purpose at the time of sale, $5.6 million remained in escrow at March 31, 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 $5.4 million 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 (including 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. In that report, the environmental firm that issued the report concluded that environmental issues exist with respect to four facilities, including the two subject to accepted claims and two of the Partnership s processing plants. The firm estimated that remediation costs associated with the processing plants would aggregate to $2.8 million. 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.

Regulatory Environment In August 2005, Congress enacted and the President signed the Energy Policy Act of 2005. With respect to the oil and gas industry, the new legislation focuses on the exploration and production sector,

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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.

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

Texas Tax legislation. On May 2, 2006, the Texas legislature passed and sent to the governor legislation that would impose a margin tax on partnerships and master limited partnerships. The Partnership currently estimates that the effect of this legislation, if adopted, will not have a material effect on its results of operations, cash flows, or financial condition.

5. Related Party Transactions

Concurrent with the closing of the Partnership s IPO, the Partnership paid $9.0 million to an affiliate of HM Capital Partners LP to terminate two management services contracts with a remaining term of 9 years and a minimum annual obligation of $1.0 million.

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. These reimbursements are recorded in the Partnership s financial statements as operating expenses or as general and administrative expenses, as appropriate.

6. Concentration Risk

The following table provides information about the extent of the Partnership s reliance on its major customers and gas suppliers. Total revenues and cost of sales from transactions with single external customers or suppliers amounting to 10% or more of the Partnership s revenues or cost of sales are disclosed below, together with the identity of the segment reporting the revenues.

Customer	Reporting Segment	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
		($ in millions)	
Alabama Gas Corporation	Transportation	37.2	24.6
Atmos Energy Marketing	Gathering and Processing	30.8	*
Koch Hydrocarbon, LP	Gathering and Processing	*	21.7
Energy Transfer Company	Gathering and Processing	*	12.8
Supplier	**Reporting Segment**		
Cohort Energy Company	Transportation	26.9	16.7
Chesapeake Energy Corporation	Transportation	20.6	*

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

periods.

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

The Partnership is a party to various commercial netting agreements that allow it and contractual counterparties to net receivable and payable obligations. These agreements are customary and the terms follow standard industry practice. In the opinion of management, these agreements reduce the overall counterparty credit risk exposure.

7. 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.

Regency Energy Partners LP
Segment Information

	Gathering and Processing	Transportation	Corporate	Eliminations	Consolidated Total
		($ in millions)			
External Revenue					
For the three months ended March 31, 2006	134.1	67.4			201.5
For the three months ended March 31, 2005	76.1	30.5			106.6
Intersegment Revenue					
For the three months ended March 31, 2006		8.5		(8.5)	
For the three months ended March 31, 2005		8.3		(8.3)	
Cost of Sales					
For the three months ended March 31, 2006	116.6	57.5			174.1
For the three months ended March 31, 2005	78.3	28.1			106.4
Segment Margin					
For the three months ended March 31, 2006	17.5	9.9			27.4
For the three months ended March 31, 2005	(2.2)	2.4			0.2
Operating Expenses					
	4.9	1.1			6.0

For the three months ended March 31, 2006				
For the three months ended March 31, 2005	4.6	0.3		4.9
Depreciation and Amortization				
For the three months ended March 31, 2006	4.3	3.0	0.2	7.5
For the three months ended March 31, 2005	4.1	1.0	0.1	5.2
Assets				
March 31, 2006	327.1	298.8	17.1	643.0
December 31, 2005	342.6	292.0	19.7	654.3
Expenditures for Long-Lived Assets				
For the three months ended March 31, 2006	12.4	15.5	0.5	28.4
For the three months ended March 31, 2005	1.9	2.2	0.2	4.3

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

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

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
	($ in millions)	
Total Segment Margin (from above)	$ 27.4	$ 0.2
Operating expenses	6.0	4.9
General and administrative	4.8	2.3
Transaction expenses	9.0	
Depreciation and amortization	7.5	5.1
OPERATING INCOME	0.1	(12.1)
OTHER INCOME AND DEDUCTIONS		
Interest expense, net	(6.5)	(3.2)
Other income and deductions, net	0.1	0.1
Total other income and deductions	(6.4)	(3.1)
NET LOSS FROM CONTINUING OPERATIONS	$ (6.3)	$ (15.2)

8. Equity-Based Compensation On December 12, 2005, the compensation committee of the board of directors approved a long-term incentive plan (LTIP) for the Partnership s employees 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 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 March 31, 2006, grants have been made in the amounts of 362,500 restricted common units and 657,300 common unit options with weighted average grant-date fair values of $20.10 per unit and $1.15 per option. The options were valued with the Black-Scholes Option Pricing Model assuming 15% volatility in the unit price, a ten year term, a strike price equal to the grant-date price per unit, a distribution per unit of $1.40 per year, a risk-free rate of 4.25%, 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, these awards represent 1,019,800 potential common units.

The Partnership will make distributions to non-vested restricted common units on a 1:1 ratio with the per unit distributions paid to common units. Upon the vesting of the restricted common units and the exercise of the common unit options, the Partnership intends to settle these obligations with common units. Accordingly, the Partnership expects to recognize an aggregate of $7.6 million of compensation expense related to the grants under LTIP, or $2.5 million for each of the three years of the vesting period for such grants. The Partnership has adopted SFAS 123(R) Share-Based Payment for accounting for its LTIP. The timing of the inception of the LTIP allowed the Partnership to adopt SFAS 123(R) in the first quarter of 2006 with no associated changes in accounting principles.

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Options	Units	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term in Years	Aggregate Intrinsic Value* ($ in thousands)
Outstanding at December 31, 2005				
Granted	657,300	$ 20.01		
Exercised				
Forfeited or expired	(3,300)	20.00		
Outstanding at March 31, 2006	654,000	20.01	9.8	$ 1,366
Exercisable at March 31, 2006				

Restricted (Nonvested) Units	Units	Weighted Average Grant-Date Fair Value
Outstanding at December 31, 2005		
Granted	362,500	$ 20.10
Forfeited		
Outstanding at March 31, 2006	362,500	$ 20.10

* Intrinsic value equals the closing market price of a unit less the option strike price, multiplied by the number of unit options awarded.

9. Subsequent Event

On April 27, 2006, the Partnership declared a distribution of $0.2217 per common and subordinated unit, payable to unitholders of record as of May 8, 2006. The distribution will be paid on May 15, 2006, and constitutes the minimum quarterly distribution prorated for the period in the first quarter of 2006 since the closing of the Partnership s initial public offering (February 3, 2006).

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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% 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 million, 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.

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

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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 loss.

	Three Months Ended March 31,	
	2006	2005
	($ in thousands)	
Reconciliation of total segment margin to net loss		
Net loss	$ (6,270)	$ (15,141)
Add (deduct):		
Operating expenses	6,046	4,874
General and administrative	4,768	2,292
Management services termination fee	9,000	
Depreciation and amortization	7,477	5,161
Interest expense, net	6,441	3,189
Other income and deductions, net	(88)	(60)
Discontinued operations		(52)
Total segment margin (1)	27,374	$ $263

(1) In 2005 includes $18.3 million of unrealized losses on 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 loss and net cash flows provided by (used in) operating activities

	Three Months Ended March 31,	
	2006	2005
	($ in thousands)	
Reconciliation of EBITDA to net cash flows provided by (used in) operating activities and to net loss		
Net cash flows provided by (used in) operating activities	$ (397)	$ 4,906
Add (deduct):		
Depreciation and amortization	(7,628)	(5,557)
Risk management portfolio value changes	191	(17,325)
Long-term incentive plan	(314)	
Accounts receivable	(13,751)	(1,917)
Other current assets	(742)	(772)
Accounts payable and accrued liabilities	18,899	4,334
Accrued taxes payable	(179)	(120)
Other current liabilities	(12)	1,178
Other assets	(2,963)	132
Other liabilities	626	
Net loss	$ (6,270)	$ (15,141)
Add:		
Interest expense, net	6,441	3,189
Depreciation and amortization	7,477	5,161
EBITDA (1)	$ 7,648	$ (6,791)

(1) In 2005 includes $18.3 million of unrealized losses on hedging transactions

Cash Available for Distribution. We define cash available for distribution as:

EBITDA,

plus or minus non-cash items affecting EBITDA, such as non-cash Long-Term Incentive Plan (LTIP) expense and unrealized gains and losses resulting from risk management activities,

minus cash interest expense,

minus maintenance capital expenditures,

plus cash proceeds from asset sales, if any.

Additionally, in the first quarter, we made an adjustment for the termination fee paid to HM Capital, which was paid with proceeds from our initial public offering rather than with cash from the Partnership s operations.

Cash available for distribution 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 approximate the amount of Operating Surplus generated by the Partnership during a specific period. Cash available for distribution is a supplemental liquidity measure used by our management and by external users of our financial statements to assess our ability to make cash distributions to our unitholders and our general partner. Cash available for distribution is not the same measure as Operating Surplus or Available Cash, both of which are defined in our partnership agreement. Following the payment of our first quarter distribution, our Operating Surplus will be $37.8 million.

Cash available for distribution 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.

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The following table provides a reconciliation of cash available for distribution to net cash flows from operating activities and to net loss:

		Three Months Ended March 31, 2006 ($ in thousands)
Reconciliation of cash available for distribution to net cash flows provided by (used in) operating activities and to net loss		
Net cash flows provided by (used in) operating activities	$	(397)
Add (deduct):		
Depreciation and amortization		(7,628)
Risk management portfolio value changes		191
Long-term incentive plan		(314)
Accounts receivable		(13,751)
Other current assets		(742)
Accounts payable and accrued liabilities		18,899
Accrued taxes payable		(179)
Other current liabilities		(12)
Other assets		(2,963)
Other liabilities		626
Net loss	$	(6,270)
Add:		
Interest expense, net		6,441
Depreciation and amortization		7,477
EBITDA	$	7,648
Add (deduct):		
Unrealized loss (gain) from risk management activities		(1,053)
Non-cash put option expiration		803
Management services termination fee		9,000
Long-term incentive plan		314
Cash interest expense		(6,251)
Maintenance capital expenditures		(1,811)
Cash available for distribution	$	8,650

Declared Cash Distribution

On April 27, 2006, the Partnership declared a distribution of $0.2217 per common and subordinated unit, payable to unitholders of record as of May 8, 2006. The distribution will be paid on May 15, 2006, and 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 initial public offering (February 3, 2006).

Results of Operations

Three Months Ended March 31, 2006 vs. Three Months Ended March 31, 2005

The results of operations for the three months ended March 31, 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 three months of operation. Through May 12, 2006, we have signed definitive agreements for 497,000 MMBtu/d of firm transportation on the Regency Intrastate Pipeline system and 409,000 MMBtu/d of interruptible transportation. The volume and segment margin delivered by our transportation segment was, however, adversely affected by delayed pipeline interconnections and pipeline pressure issues on the part of certain customers and downstream markets. All interconnection

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issues were resolved during the first quarter, and we have begun implementing plans that will resolve the pipeline pressure issues and ultimately expand the capacity of the pipeline to 860,000 Mcf/d.
In the three months ended March 31, 2006, we recorded a one-time charge of $9 million 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:

We expect volumes on our gathering and processing segment to remain at approximately the same levels as those experienced in 2005. Because our hedging program locks in more favorable pricing in 2006 as compared to 2005, we expect to earn higher segment margins on these volumes.

We currently expect to spend approximately $62 million for organic growth capital expenditures in 2006, including two new projects recently approved by our Board of Directors totaling approximately $36 million. Both of the new projects are expected to be operational in the second half of 2006. Please read Capital Requirements below.

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

	Three Months Ended March 31, 2006	2005 ($ in millions)	Favorable/ (Unfavorable)	Percent
Revenues (a)	$ 201.5	$ 106.6	$ 94.9	89%
Cost of sales	174.1	106.4	(67.7)	(64)
Total segment margin	27.4	0.2	27.2	n/m
Operating expenses	6.0	4.9	(1.1)	(22)
General and administrative	4.8	2.3	(2.5)	(109)
Management services termination fee (b)	9.0		(9.0)	n/m
Depreciation and amortization	7.5	5.1	(2.4)	(47)
Operating income	0.1	(12.1)	12.2	101
Interest expense, net	(6.5)	(3.2)	(3.3)	(103)
Other income and deductions, net	0.1	0.1		0
Net loss from continuing operations	(6.3)	(15.2)	8.9	59
Discontinued operations		0.1	(0.1)	(100)
Net loss	$ (6.3)	$ (15.1)	$ 8.8	58%
System inlet volumes (MMbtu/d) (c)	738,115	484,588	253,527	52%

Processing volumes (MMbtu/d) (d)	173,621	248,212	(74,591)	(30)

(a) 2005 revenues include unrealized losses from risk management activities of $18.3 million.

(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.

n/m = not meaningful

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Net Loss. Net loss for the three months ended March 31, 2006 decreased $8.8 million compared with the three months ended March 31, 2005. Total segment margin increased $27.2 million primarily due to increased segment margin in the transportation segment of $7.5 million and an unrealized loss of $18.3 million from risk management activities related to mark-to-market accounting in the three months ended March 31, 2005. The remaining price and volume variances in total segment margin are discussed below.

Earnings for the first quarter of 2006 were adversely affected by a one-time $9 million 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. Interest expense, net increased approximately $3.3 million. Of this increase, approximately $2.1 million is due to higher levels of borrowing primarily associated with our Regency Intrastate Enhancement Project and the remaining $1.2 million is attributable to higher interest rates. General and administrative expenses increased $2.5 million, depreciation and amortization increased $2.4 million and operating expenses increased $1.1 million.

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

	Three Months Ended March 31, 2006	2005	Favorable/ (Unfavorable)	Percent
	($ in millions)			
Segment Financial and Operating Data:				
Gathering and Processing Segment				
Financial data:				
Segment Margin (a)	$ 17.5	$ (2.2)	$ 19.7	895%
Operating expenses	4.9	4.6	(0.3)	(7)
Operating data:				
Throughput (MMbtu/d)	299,719	310,743	(11,024)	(4)
NGL gross production (Bbls/d)	13,862	15,524	(1,662)	(11)
Transportation Segment				
Financial data:				
Segment Margin	$ 9.9	$ 2.4	$ 7.5	313%
Operating expenses	1.1	0.3	(0.8)	(267)
Operating data:				
Throughput (MMbtu/d)	438,396	173,845	264,551	152

(a) 2005 revenues include unrealized losses from risk management activities of $18.3 million.

Total Segment Margin. Total segment margin for the three months ended March 31, 2006 increased to $27.4 million from $0.2 million for the corresponding period in 2005. This increase resulted in part from the nonrecurrence of $18.3 million in non-cash losses incurred in the three months ended March 31, 2005. These non-cash losses were caused by the net change in the fair market value of derivative contracts since the contracts were marked to market and not designated for hedge accounting treatment under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities at March 31, 2005. Segment margin in the transportation segment increased $7.5 million primarily attributable to the Regency Intrastate Enhancement Project, as detailed below. The remaining increase in total segment margin resulted primarily from higher pricing in our executed NGL hedges.

Gathering and Processing Segment. Segment margin for the gathering and processing segment for the three months ended March 31, 2006 increased to $17.5 million from $(2.2) million for the three months ended March 31, 2005. The elements of this increase in segment margin are as follows:

- a reduction of non-cash losses in the fair market value of derivative contracts in the amount of $18.3 million which were recorded during the first three months of 2005,

- an increase of $1.8 million in segment margin attributable to increased hedged gross margins resulting from more favorable pricing of executed hedges, and

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a reduction of $0.5 million attributable to slightly reduced throughput volumes.

In the third quarter of 2006, a gathering contract with one of our suppliers representing over 10% of the volume in a particular region will expire and will not be renewed. We believe that we will substantially replace these volumes and margins with new contracts either in that region or in one of the other regions in which we have gathering and processing activities.

Transportation Segment. Segment margin for the transportation segment for the three months ended March 31, 2006 increased to $9.9 million from $2.4 million for the comparable period in 2005, a 313% increase. The elements of this increase in segment margin are as follows:

an increase of $3.6 million attributable to increased throughput volumes

an increase of $2.1 million resulting from increased marketing activities around the expanded system

an increase of $0.9 million resulting from an average of 71 thousand MMBtu/d of unused incremental firm transportation contracted by several shippers, and

an increase of $0.9 million resulting from higher average transportation fees.

In spite of this significant increase in the transportation segment margin, our transportation volumes and margin would have been greater but for the aforementioned interconnect delays and pressure issues. Prior to completion of the interconnection of our Regency Intrastate Enhancement Project to a major downstream pipeline, that pipeline experienced a casualty loss of two large turbine compressors. Upon completion of the interconnection, this compression failure caused pressures at the interconnection to exceed design expectations significantly, restricting access to our pipeline by certain of our shippers. Coincidentally, intermittent pipeline pressure issues at one of our upstream interconnections required us to reduce pressures on the western end of our system. As a result, throughput volumes on our intrastate pipeline have been lower during the quarter than we could have experienced but for those external issues.

We are addressing these issues in several ways. The downstream pipeline has advised us that it is constructing replacement compression which should be operational in the fourth quarter of this year. In addition, we have initiated the installation of additional compression on our North Louisiana system and have commenced a looping project that will result in additional pipeline capacity to de-bottleneck a portion of the western end of the system. These projects will resolve the remaining pipeline pressure issues and ultimately expand the capacity of the pipeline to 860,000 Mcf/d. Please see additional information related to the capital projects discussed below at Capital Requirements.

Operating Expenses. Operating expenses for the three months ended March 31, 2006 increased to $6.0 million from $4.9 million for the corresponding period in 2005, representing a 22% increase. This increase resulted in part from an increase in non-income taxes ($0.4 million), mainly associated with our Regency Intrastate Enhancement Project in our Transportation Segment. The remaining $0.7 million is attributable to employee expenses, overtime related to maintenance events on compression equipment located in the north Louisiana region ($0.3 million), and company-wide accrued vacation, benefits, and other estimated costs ($0.4 million).

General and Administrative. General and administrative expense increased to $4.8 million in the three months ended March 31, 2006 from $2.3 million for the comparable period in 2005. This increase was primarily attributable to higher employee-related expenses of $1.5 million, including higher salary expense associated with hiring key personnel to assist in achieving our partnership s strategic objectives. Also contributing to the increase were increased professional and consulting expenses of $0.6 million, consisting primarily of audit fees and consulting fees for Sarbanes-Oxley compliance support. Our external Sarbanes-Oxley compliance support was completed during the first quarter. Key resources to advance our internal controls effort have been hired as employees, and as a result, we do not expect to incur significant external Sarbanes-Oxley compliance support expense during the remainder of 2006. In addition, we accrued a non-cash expense associated with our new long-term incentive plan of $0.3 million in the three months ended March 31, 2006.

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 public entity and completing the major enhancement project.

Management Services Termination Fee. In the three months ended March 31, 2006, we incurred $9.0 million of expense related to the termination of our two long-term management services contracts with an affiliate of HM Capital Partners, which was funded by the proceeds of our IPO.

Depreciation and Amortization. Depreciation and amortization increased to $7.5 million in the three months ended March 31, 2006 from $5.1 million for the corresponding period in 2005, representing a 47% increase. Depreciation expense increased $2.4 million 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 approximately $3.3 million, or 103%, in the three months ended March 31, 2006 compared to the three months ended March 31, 2005. Of the increase, approximately $2.1 million is due to higher levels of borrowings primarily associated with our Regency Intrastate Enhancement Project and the remaining $1.2 million is attributable to higher interest rates.

Critical Accounting Policies

Revenue and Cost of Sales Estimation. Prior to March 2006, we recorded the monthly results of operations using actual results which included settling most of our volumes with producers, shippers, and customers at about the 25th day of the month following the production month. This process resulted in a delay in reporting results. To expedite financial reporting, we have implemented a financial closing process in March 2006 that eliminates the reporting lag. Prior to the settlement date, we record actual operating data to the extent available, such as actual operating and maintenance and other expenses. For total segment margin, we estimate volumes using actual pricing and nominated volumes and record the resulting accrual. In the subsequent production month, we then reverse the accrual and record the actual results. The new process conforms to industry practice.

Equity Based Compensation. In December 2005, the compensation committee of the board of directors of Regency GP LLC (our Managing GP) approved a long-term incentive plan, or LTIP, for our employees, directors and consultants. The aggregate of the grants made as of March 31, 2006 include a total of 657,300 common unit options and 362,500 restricted common units with weighted average grant-date fair values of $1.15 per option and $20.10 per unit. In the aggregate, these awards represent 1,019,800 potential common units. The options were valued with the Black-Scholes Option Pricing Model under the following assumptions: 15% volatility in the unit price, a ten year term, a strike price equal to the grant-date price per unit, a distribution per unit of $1.40 per year, and an average exercise of the options of four years after vesting is complete. The assumption that participants will, on average, exercise their options four years from the vesting date is based on the average of the mid-points from vesting to expiration of the options.

A total of 2,865,584 common units have been authorized for delivery under the LTIP. LTIP awards vest on the basis of one-third of the units subject thereto each year. The options have a maximum contractual term, expiring ten years after the grant date.

We will make the same distributions to holders of non-vested restricted common units as those paid to common unitholders. Upon the vesting of the restricted common units and the exercise of the common unit options, we intend to settle these obligations with common units. Accordingly, we expect to recognize an aggregate of $7.6 million of compensation expense related to the initial grants under LTIP, or $2.5 million for each of the three years of the vesting period for such grants. We adopted SFAS 123(R) Share-Based Payment in the first quarter of 2006 which 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 million) for environmental losses as to which El Paso was deemed responsible. Of the cash escrowed for this purpose at the time of sale, $5.5 million remained in escrow at March 31, 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 $5.4 million 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 (including 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. In that report, the environmental firm that issued the report concluded that environmental issues exist with respect to four facilities, including the two subject to accepted claims and two of our processing plants. The firm estimated that remediation costs associated with the processing plants would aggregate $2,750,000. We believe any obligation of ours to remediate the properties is subject to the indemnity under the El Paso PSA. We intend to reinstate the claims for indemnification for these plant sites.

Texas Tax Legislation On May 2, 2006, the Texas legislature passed and sent to the governor legislation that would impose a margin tax on partnerships and master limited partnerships. We currently estimate that the effect of this legislation, if adopted, 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. Certain factors, as discussed below, affect working capital but not our ability to pay bills as they come due. Our working capital was $(4.5) million at March 31, 2006 and $(27.7) million at December 31, 2005.

The net increase in working capital from December 31, 2005 to March 31, 2006 of $23.2 million resulted primarily from:

- a decrease in the excess of accounts payable over accounts receivable to $0.7 million from $21.0 million primarily attributable to a decrease of $15.1 million in construction payables, which were primarily funded with borrowings from the revolving credit facility rather than cash from operations,

- a $4.4 million decrease in the net current liability valuation of our risk management contracts due to lower NGL prices and increases in interest rates,

- partially offset by a decrease in cash and cash equivalents of $1.2 million.

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. 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.

Cash Flows from Operations. Net cash flows provided by operating activities decreased $5.3 million, or 108%, in the three months ended March 31, 2006 compared to the corresponding period in 2005. The decrease was primarily the result of paying a non-recurring management services termination fee of $9.0 million to an affiliate of HM Capital funded with proceeds from the IPO in the three months ended March 31, 2006. Also contributing to the decline was an increase in cash interest paid of $2.5 million resulting primarily from increased levels of borrowings associated with our Regency Intrastate Enhancement Project and, to a lesser extent, increased interest rates. Partially offsetting the decline in net cash flows provided by operating activities was improved segment margins in both the transportation segment and gas gathering segment. The noticeable improvement in segment margin in the transportation segment is attributed to the completion of our Regency Intrastate Enhancement Project.

Cash Flows Used in Investing Activities. Net cash flows used in investing activities increased $18.3 million, or 181%, in the three months ended March 31, 2006 compared to the three months ended March 31, 2005. The increase is primarily due to higher levels of capital expenditures related to the completion of our Regency Intrastate Enhancement Project. The increase in net cash flows used in investing activities would have been greater but for a $5.8 million cash outflow in the three months ended March 31, 2005 related to post closing adjustments under the purchase and sale agreement associated with HM Capital s December 1, 2004 acquisition of Regency Gas Services LLC.

Cash Flows Provided by Financing Activities. Net cash flows provided by financing activities increased $23.2 million, or 521%, in the three months ended March 31, 2006 compared to the corresponding period in 2005. The increase is primarily due to financing activity related to our initial public offering, which closed on February 3, 2006, and an increase in borrowings under our revolving credit facility. The funds flow of our initial public offering, the related over allotment option and the additional borrowings from our revolving credit facility are given below.

$257.0 million of initial public offering proceeds, net of issuance costs,

$195.8 million of capital reimbursement paid to affiliates of HM Capital,

$48.0 million of working capital distribution to affiliates of HM Capital,

$4.2 million of offering costs in connection with our initial public offering,

$13.8 million of working capital and growth capital expenditures financed with additional borrowings under our credit facility

$26.2 million of net proceeds from the exercise of the over allotment option, and

$26.2 million of net proceeds from the over allotment option transferred to HM Capital.

Capital Requirements

Growth and Maintenance Capital Expenditures. In the three months ended March 31, 2006, we incurred $10.8 million of growth capital expenditures and $1.8 million of maintenance capital expenditures. The majority of the growth capital expenditures were incurred in connection with the completion of our Regency Intrastate Enhancement Project.

We expect to spend approximately $62 million for organic growth capital expenditures in 2006 as compared to our estimate of $25.1 million disclosed in our Annual Report on Form 10-K for the year ended December 31, 2005.

Substantially all of the balance of organic growth capital spending relates to $36 million for two new projects recently approved by our board. 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, and a new 200 MMcf/d dewpoint control facility scheduled for installation on our intrastate pipeline in Webster Parish, Louisiana. 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.

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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% of our expected exposure to NGL prices in 2006, approximately 75% in 2007, and approximately 50% in 2008. We continually monitor our hedging and contract portfolio and expect to continue to adjust our hedge position as conditions warrant.

The following table sets forth certain information regarding our non-trading NGL swaps outstanding at March 31, 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 ($/gallon)	Fair Value ($ thousands)
Mar 2006	Dec 2008	Ethane	1,025	Index	$0.55 - $0.58	(1,593)
Mar 2006	Dec 2008	Propane	929	Index	$0.66 - $0.93	(6,967)
Mar 2006	Dec 2008	Butane	484	Index	$1.03 - $1.12	(2,144)
Mar 2006	Dec 2008	Natural Gasoline	200	Index	$1.22 - $1.41	(1,436)
Total Fair Value						(12,140)

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

Period		Commodity	Notional Volume (MBbls)	Strike Prices ($/BBL)	Fair Value ($ in thousands)
Mar 2006	Dec 2007	NYMEX West Texas Intermediate Crude	2,175	$30.00 to $36.50	$71

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)
Mar 2006	Mar 2009	Floating to Fixed	$200 million	3.95%	4.61%	LIBOR	$4,343

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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 March 31, 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 are 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 March 31, 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 adversely affect our ability to properly record, process, summarize and report financial information, we reported that matter to our independent registered public accounting firm and to the audit committee of our board of directors.

As previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2005, during the preparation of our financial statements for that year, an accounting error was discovered relating to the reclassification of losses from other comprehensive income to earnings which understated net income (loss) and overstated other comprehensive income (loss) during the last six months of 2005. The error was the result of a material weakness in our internal controls over financial reporting. As a result, management instituted a change in our internal control over financial reporting in the three months ended March 31, 2006 designed to avoid any repetition of the error. That change in our internal control over financial reporting was a requirement to conduct a thorough reconciliation of the components of other comprehensive income (loss) on a monthly basis.

In addition, we implemented a process for estimating revenues, cost of gas and liquids and certain other expenses and the recording thereof during the quarter. We expect this new process to improve the timeliness of financial reporting and our control environment. See Item 1 Financial Statements, Notes to Financial Statements, Note 1. There have been no other changes in our internal controls over financial reporting that occurred during the three months ended March 31, 2006 that have materially affected, or are reasonably likely to affect materially, our internal controls 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 4, 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, Business Operations 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)

May 15, 2006

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