Regency Energy Partners LP
Form 10-Q
November 07, 2011
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2011
OR

¨ 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: 001-35262
REGENCY ENERGY PARTNERS LP
(Exact name of registrant as specified in its charter)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨

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

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

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

The issuer had 157,343,942 common units outstanding as of October 25, 2011.

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Regency Energy Partners LP

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Introductory Statement

References in this report to the “Partnership,” “we,” “our,” “us” and similar terms, when used in an historical context, refer to Regency Energy Partners LP and its subsidiaries. When used in the present tense or prospectively, these terms refer to the Partnership and its subsidiaries. We use the following definitions in this quarterly report on Form 10-Q:

Name	Definition or Description
/d	Per day
AOCI	Accumulated Other Comprehensive Income
Bbls	Barrels
BTU	A unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit
EPD	Enterprise Products Partners L.P.
ETC	Energy Transfer Company, the name assumed by La Grange Acquisition, L.P. for conducting business and shared services, a wholly owned subsidiary of ETP
ETE	Energy Transfer Equity, L.P.
ETE GP	ETE GP Acquirer LLC
ETP	Energy Transfer Partners, L.P.
FASB	Financial Accounting Standards Board
Finance Corp.	Regency Energy Finance Corp., a wholly-owned subsidiary of the Partnership
GAAP	Accounting principles generally accepted in the United States of America
GE EFS	General Electric Energy Financial Services, combined with Regency GP Acquirer, L.P. and Regency LP Acquirer, L.P.
General Partner	Regency GP LP, the general partner of the Partnership, or Regency GP LLC, the general partner of Regency GP LP, which effectively manages the business and affairs of the partnerships
GPM	Gallons per minute
GP Seller	Regency GP Acquirer, L.P.
HPC	RIGS Haynesville Partnership Co., a general partnership in which the Partnership owns a 49.99% interest and its 100% owned subsidiary, Regency Intrastate Gas LP
IDRs	Incentive Distribution Rights
IRS	Internal Revenue Service
LDH	LDH Energy Asset Holdings LLC
LIBOR	London Interbank Offered Rate
Lone Star	Lone Star NGL LLC, a joint venture that is 30% owned by the Partnership and 70% owned by ETP
LTIP	Long-Term Incentive Plan
MEP	Midcontinent Express Pipeline LLC, a joint venture in which the Partnership currently owns a 50% interest
MMBtu	One million BTUs
NGLs	Natural gas liquids, including ethane, propane, normal butane, iso butane and natural gasoline
NYMEX	New York Mercantile Exchange
Partnership	Regency Energy Partners LP
RGS	Regency Gas Services LP, a wholly-owned subsidiary of the Partnership
RIGS	Regency Intrastate Gas System
SEC	Securities and Exchange Commission
Series A Preferred Units	Series A convertible redeemable preferred units

Services Co.	ETE Services Company, LLC, a wholly owned subsidiary of ETE
WTI	West Texas Intermediate Crude
Zephyr	Zephyr Gas Services LLC, a wholly owned subsidiary of the Partnership

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Cautionary Statement about Forward-Looking Statements

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

- volatility in the price of oil, natural gas, and NGLs;
- declines in the credit markets and the availability of credit for us as well as for producers connected to our pipelines and our gathering and processing facilities, and for our customers of contract compression and contract treating businesses;
- the level of creditworthiness of, and performance by, our counterparties and customers;
- our access to capital to fund organic growth projects and acquisitions, and our ability to obtain debt or equity financing on satisfactory terms;
- our use of derivative financial instruments to hedge commodity and interest rate risks;
- the amount of collateral required to be posted from time-to-time in our transactions;
- changes in commodity prices, interest rates and demand for our services;
- changes in laws and regulations impacting the midstream sector of the natural gas industry, including those that relate to climate change and environmental protection and safety;
- weather and other natural phenomena;
- industry changes including the impact of consolidations and changes in competition;
- regulation of transportation rates on our natural gas pipelines;
- our ability to obtain indemnification related to cleanup liabilities and to clean up any hazardous materials release on satisfactory terms;
- our ability to obtain required approvals for construction or modernization of our facilities and the timing of production from such facilities; and
- the effect of accounting pronouncements issued periodically by accounting standard setting boards.

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

Other factors that could cause our actual results to differ from our projected results are discussed in Item 1A of our December 31, 2010 Annual Report on Form 10-K, our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2011 and June 30, 2011 and "Part II – Other Information - Item 1A. Risk Factors" in this Quarterly Report on Form 10-Q.

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

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PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

As disclosed in Note 1, on May 26, 2010, GP Seller sold all of the outstanding membership interests of the Partnership's General Partner to ETE, effecting a change in control of the Partnership. In connection with this transaction, the Partnership's assets and liabilities were adjusted to fair value at the acquisition date by application of "push-down" accounting. As a result, the Partnership's unaudited condensed consolidated financial statements and certain footnote disclosures are presented in two distinct periods to indicate the application of two different bases of accounting between the periods presented: (1) the period prior to the acquisition date (May 26, 2010), identified as "Predecessor" and (2) the period from May 26, 2010 forward, identified as "Successor."

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

	September 30, 2011	December 31, 2010
ASSETS		
Current Assets:		
Cash and cash equivalents	$5,231	$9,400
Trade accounts receivable, net of allowance of $546 and $297	37,444	35,212
Accrued revenues	86,682	74,017
Related party receivables	34,750	32,342
Derivative assets	4,504	2,650
Other current assets	25,222	7,384
Total current assets	193,833	161,005
Property, Plant and Equipment:		
Gathering and transmission systems	610,562	543,286
Compression equipment	839,606	812,428
Gas plants and buildings	189,251	185,741
Other property, plant and equipment	115,411	81,295
Construction-in-progress	227,527	97,439
Total property, plant and equipment	1,982,357	1,720,189
Less accumulated depreciation	(157,767)	(59,971)
Property, plant and equipment, net	1,824,590	1,660,218
Other Assets:		
Investment in unconsolidated affiliates	1,924,183	1,351,256
Long-term derivative assets	3,696	23
Other, net of accumulated amortization of debt issuance costs of $8,393 and $3,326	41,447	37,758
Total other assets	1,969,326	1,389,037
Intangible Assets and Goodwill:		
Intangible assets, net of accumulated amortization of $37,538 and $15,584	748,201	770,155
Goodwill	789,789	789,789
Total intangible assets and goodwill	1,537,990	1,559,944
TOTAL ASSETS	$5,525,739	$4,770,204
LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Trade accounts payable	$64,955	$50,208
Accrued cost of gas and liquids	92,468	80,756
Related party payables	11,633	3,338
Deferred revenues, including related party amounts of $41 and $8,765	16,838	25,257
Derivative liabilities	12,435	13,172
Other current liabilities	48,252	23,419
Total current liabilities	246,581	196,150
Long-term derivative liabilities	36,633	61,127
Other long-term liabilities	6,167	6,521
Long-term debt, net	1,800,380	1,141,061
Commitments and contingencies		
Series A Preferred Units, redemption amount of $84,659 and $83,891	71,091	70,943

Partners' capital and noncontrolling interest:		
Common units	3,003,341	2,940,732
General partner interest	330,783	333,077
Accumulated other comprehensive loss	(2,002)	(11,099)
Total partners' capital	3,332,122	3,262,710
Noncontrolling interest	32,765	31,692
Total partners' capital and noncontrolling interest	3,364,887	3,294,402
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$5,525,739	$4,770,204

See accompanying notes to condensed consolidated financial statements

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

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010
REVENUES		
Gas sales, including related party amounts of $3,840 and $1,680	$118,754	$132,130
NGL sales, including related party amounts of $103,892 and $51,062	174,537	91,489
Gathering, transportation and other fees, including related party amounts of $6,141 and $5,680	91,596	72,184
Net realized and unrealized loss from derivatives	(5,380)	(6,218)
Other, including related party amounts of $2,665 and $1,111	10,760	7,303
Total revenues	390,267	296,888
OPERATING COSTS AND EXPENSES		
Cost of sales, including related party amounts of $5,049 and $4,768	279,526	213,032
Operation and maintenance	37,950	34,306
General and administrative, including related party amounts of $4,225 and $2,500	17,350	18,072
(Gain) loss on asset sales, net	(131)	200
Depreciation and amortization	41,956	32,205
Total operating costs and expenses	376,651	297,815
OPERATING INCOME (LOSS)	13,616	(927)
Income from unconsolidated affiliates	30,946	21,754
Interest expense, net	(28,852)	(20,379)
Other income and deductions, net	15,050	7,524
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	30,760	7,972
Income tax (benefit) expense	(89)	450
INCOME FROM CONTINUING OPERATIONS	$30,849	$7,522
DISCONTINUED OPERATIONS		
Net income from operations of east Texas assets, including gain on disposal of $20 in 2010	—	324
NET INCOME	$30,849	$7,846
Net income attributable to noncontrolling interest	(549)	(58)
NET INCOME ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$30,300	$7,788
Amounts attributable to Series A Preferred Units	1,997	1,991
General partner's interest, including IDRs	2,060	1,166
Limited partners' interest in net income	$26,243	$4,631
Income from continuing operations per common unit:		
Amount allocated to common units	$26,243	$4,314
Weighted average number of common units outstanding	145,842,735	128,387,929
Basic income from continuing operations per common unit	$0.18	$0.03
Diluted income from continuing operations per common unit	$0.09	$0.03
Distributions per unit	$0.455	$0.445
Basic and diluted income from discontinued operations per common unit	$—	$—
Basic and diluted net income per common unit:		
Amount allocated to common units	$26,243	$4,631

Basic net income per common unit	$0.18	$0.04
Diluted net income per common unit	$0.09	$0.04

See accompanying notes to condensed consolidated financial statements

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

	Successor		Predecessor
	Nine Months Ended September 30, 2011	Period from Acquisition (May 26, 2010) to September 30, 2010	Period from January 1, 2010 to May 25, 2010
REVENUES			
Gas sales, including related party amounts of $15,479, $2,127 and $0	$361,641	$179,371	$228,097
NGL sales, including related party amounts of $253,933, $69,116 and $0	430,876	117,529	152,803
Gathering, transportation and other fees, including related party amounts of $17,611, $7,766 and $12,200	255,249	94,755	114,526
Net realized and unrealized loss from derivatives	(14,636)	(6,348)	(716)
Other, including related party amounts of $7,455, $1,111 and $0	30,887	8,561	10,340
Total revenues	1,064,017	393,868	505,050
OPERATING COSTS AND EXPENSES			
Cost of sales, including related party amounts of $16,070, $7,049 and $6,564	755,262	283,206	357,778
Operation and maintenance	105,506	44,708	47,842
General and administrative, including related party amounts of $12,354, $3,333 and $0	54,010	25,176	37,212
Loss on asset sales, net	50	210	303
Depreciation and amortization	122,695	42,750	41,784
Total operating costs and expenses	1,037,523	396,050	484,919
OPERATING INCOME (LOSS)	26,494	(2,182)	20,131
Income from unconsolidated affiliates	86,921	29,875	15,872
Interest expense, net	(73,548)	(28,460)	(36,321)
Other income and deductions, net	20,105	4,003	(3,897)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	59,972	3,236	(4,215)
Income tax (benefit) expense	(19)	695	404
INCOME (LOSS) FROM CONTINUING OPERATIONS	$59,991	$2,541	$(4,619)
DISCONTINUED OPERATIONS			
Net income (loss) from operations of east Texas assets, including gain on disposal of $20 in 2010 Successor period	—	410	(327)
NET INCOME (LOSS)	$59,991	$2,951	$(4,946)
Net income attributable to noncontrolling interest	(1,073)	(87)	(406)
NET INCOME (LOSS) ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$58,918	$2,864	$(5,352)
Amounts attributable to Series A Preferred Units	5,985	2,659	3,336
General partner’s interest, including IDRs	4,902	1,969	662
Amount allocated to non-vested common units	—	—	(79)
Limited partners’ interest in net income (loss)	$48,031	$(1,764)	$(9,271)

Income (loss) from continuing operations per common unit:			
Amount allocated to common units	$48,031	$(2,165)	$ (8,966)
Weighted average number of common units outstanding	142,058,631	125,916,507	92,788,319
Basic income (loss) from continuing operations per common unit	$0.34	$(0.02)	$ (0.10)
Diluted income (loss) from continuing operations per common unit	$0.23	$(0.02)	$ (0.10)
Distributions per unit	$1.35	$0.445	$ 0.89
Basic and diluted income from discontinued operations per common unit	$—	$—	$ —
Basic and diluted net income (loss) per common unit:			
Amount allocated to common units	$48,031	$(1,764)	$ (9,271)
Basic net income (loss) per common unit	$0.34	$(0.01)	$ (0.10)
Diluted net income (loss) per common unit	$0.23	$(0.01)	$ (0.10)

See accompanying notes to condensed consolidated financial statements

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

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010
Net income	$30,849	$7,846
Net cash flow hedge amounts reclassified to earnings	5,282	—
Change in fair value of cash flow hedges	10,287	—
Comprehensive income	46,418	7,846
Comprehensive income attributable to noncontrolling interest	549	58
Comprehensive income attributable to Regency Energy Partners LP	$45,869	$7,788

	Successor		Predecessor
	Nine Months Ended September 30, 2011	Period from Acquisition (May 26, 2010) to September 30, 2010	Period from January 1, 2010 to May 25, 2010
Net income (loss)	$59,991	$2,951	$(4,946)
Net cash flow hedge amounts reclassified to earnings	14,276	—	2,145
Net change in fair value of cash flow hedges	(5,179)	—	18,486
Comprehensive income	69,088	2,951	15,685
Comprehensive income attributable to noncontrolling interest	1,073	87	406
Comprehensive income attributable to Regency Energy Partners LP	$68,015	$2,864	$15,279

See accompanying notes to condensed consolidated financial statements

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

	Successor		Predecessor
	Nine Months Ended September 30, 2011	Period from Acquisition (May 26, 2010) to September 30, 2010	Period from January 1, 2010 to May 25, 2010
OPERATING ACTIVITIES:			
Net income (loss)	$59,991	$2,951	$(4,946)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:			
Depreciation and amortization, including debt issuance cost amortization and bond premium amortization	127,079	44,767	49,363
Write-off of debt issuance costs	—	—	1,780
Amortization of excess fair value of unconsolidated affiliates	4,385	—	—
Equity in earnings of unconsolidated affiliates	(91,306)	(29,875)	(15,872)
Derivative valuation changes	(21,660)	14,837	12,004
Loss on asset sales, net	50	190	303
Unit-based compensation expenses	2,444	440	12,070
Cash flow changes in current assets and liabilities:			
Trade accounts receivable, accrued revenues and related party receivables	(13,298)	13,307	(11,272)
Other current assets	186	903	2,516
Trade accounts payable, accrued cost of gas and liquids, related party payables and deferred revenues	20,467	(30,026)	8,649
Other current liabilities	24,833	(8,186)	22,614
Distributions received from unconsolidated affiliates	91,306	29,875	12,446
Other assets and liabilities	(61)	(701)	(234)
Net cash flows provided by operating activities	204,416	38,482	89,421
INVESTING ACTIVITIES:			
Capital expenditures	(290,889)	(88,202)	(63,787)
Capital contributions to unconsolidated affiliates	(23,646)	(38,922)	(20,210)
Distribution in excess of earnings of unconsolidated affiliates	40,354	50,262	—
Acquisitions of investments in unconsolidated affiliates, net of cash received	(593,843)	12,848	(75,114)
Acquisition of Zephyr, net of $1,983 cash received	—	(191,313)	—
Proceeds from asset sales	10,232	70,302	10,661
Net cash flows used in investing activities	(857,792)	(185,025)	(148,450)
FINANCING ACTIVITIES:			
Net borrowings (repayments) under revolving credit facility	160,000	(243,651)	199,008
Proceeds from issuance of senior notes	500,000	—	—
Debt issuance costs	(9,955)	(148)	(15,728)

Drafts payable	—	8,848	—
Partner contributions	—	19,724	—
Partner distributions	(199,640)	(55,251)	(86,078)
Disposition of assets between entities under common control in excess of historical cost	66	—	(16,973)
Distributions to noncontrolling interest	—	—	(1,135)
Proceeds from issuance of common units under LTIP, net of tax withholding	655	145	(4,874)
Proceeds from common unit issuances, net of issuance costs	203,917	399,872	(89)
Distributions to Series A Preferred Units	(5,836)	(1,945)	(1,945)
Net cash flows provided by financing activities	649,207	127,594	72,186
Net change in cash and cash equivalents	(4,169)	(18,949)	13,157
Cash and cash equivalents at beginning of period	9,400	22,984	9,827
Cash and cash equivalents at end of period	$5,231	$4,035	$22,984
Supplemental cash flow information:			
Non-cash capital expenditures	$25,504	$28,821	$18,051
Issuance of common units for an acquisition	—	584,436	—
Deemed contribution from acquisition of assets between entities under common control	177	17,152	—
Release of escrow payable from restricted cash	—	1,011	500
Interest paid, net of amounts capitalized	47,303	32,425	5,410
Income taxes paid	—	634	378

See accompanying notes to condensed consolidated financial statements

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

	Regency Energy Partners LP Units					
	Common	Common Unitholders	General Partner Interest	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Total
Balance - December 31, 2010	137,281,336	$2,940,732	$333,077	$ (11,099)	$ 31,692	$3,294,402
Private common unit offering, net of costs	8,500,001	203,917	—	—	—	203,917
Issuance of common units under LTIP, net of forfeitures and tax withholding	62,605	655	—	—	—	655
Unit-based compensation expenses	—	2,444	—	—	—	2,444
Transfer of assets between entities under common control	—	—	243	—	—	243
Partner distributions	—	(192,313)	(7,327)	—	—	(199,640)
Accrued distributions to phantom units	—	(238)	—	—	—	(238)
Net income	—	54,016	4,902	—	1,073	59,991
Distributions to Series A Preferred Units	—	(5,724)	(112)	—	—	(5,836)
Accretion of Series A Preferred Units	—	(148)	—	—	—	(148)
Net cash flow hedge amounts reclassified to earnings	—	—	—	14,276	—	14,276
Change in fair value of cash flow hedges	—	—	—	(5,179)	—	(5,179)
Balance - September 30, 2011	145,843,942	$3,003,341	$330,783	$ (2,002)	$ 32,765	$3,364,887

See accompanying notes to condensed consolidated financial statements

Regency Energy Partners LP
Notes to Condensed Consolidated Financial Statements
(Tabular dollar amounts, except per unit data, are in thousands)
(unaudited)

1. Organization and Summary of Significant Accounting Policies

Organization. The unaudited condensed consolidated financial statements presented herein contain the results of Regency Energy Partners LP and its subsidiaries. The Partnership and its subsidiaries are engaged in the business of gathering and processing, contract compression, treating, transportation, fractionation and storage of natural gas and NGLs. Regency GP LP is the Partnership's general partner and Regency GP LLC (collectively the "General Partner") is the managing general partner of the Partnership and the general partner of Regency GP LP.

Basis of Presentation. In May 2010, GP Seller completed the sale of all of the outstanding membership interests of the General Partner pursuant to a Purchase Agreement (the "Purchase Agreement") among itself, ETE and ETE GP (the "ETE Acquisition"). Prior to the closing of the Purchase Agreement, GP Seller, an affiliate of GE EFS, owned all of the outstanding limited partner interests in the General Partner and, as a result of that position, controlled the Partnership. As a result of this transaction, the outstanding voting interests of the General Partner and control of the Partnership were transferred from GE EFS to ETE.

In connection with this change in control, the Partnership's assets and liabilities were adjusted to fair value on the closing date (May 26, 2010) by application of "push-down" accounting (the "Push-down Adjustments"). Due to the Push-down Adjustments, the Partnership's unaudited condensed consolidated financial statements and certain footnote disclosures are presented in two distinct periods to indicate the application of two different bases of accounting between the periods presented: (1) the period prior to the acquisition date (May 26, 2010), identified as "Predecessor" and (2) the period from May 26, 2010 forward, identified as "Successor."

The unaudited financial information included in this Form 10-Q 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, 2010. In the opinion of the Partnership's management, such financial information reflects all adjustments necessary for a fair presentation of the financial position and the results of operations for such interim periods in accordance with GAAP. All inter-company 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 numbers have been reclassified to conform to the current year presentation.

Use of Estimates. The unaudited condensed consolidated financial statements have been prepared in conformity with GAAP, which includes the use of estimates and assumptions made by management that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities that exist at the date of the condensed consolidated financial statements. Although these estimates are based on management's available knowledge of current and expected future events, actual results could be different from those estimates.

Recently Issued Accounting Standards. In September 2011, the FASB issued Accounting Standards Update No. 2011-08, Intangibles - Goodwill and Other (Topic 350): Testing Goodwill for Impairment ("ASU 2011-08"), which simplifies how entities test goodwill for impairment. ASU 2011-08 gives entities the option, under certain circumstances, to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether further impairment testing is necessary. ASU 2011-08 is effective for fiscal years beginning after December 15, 2011, and early adoption is permitted. The Partnership is currently evaluating early adoption of ASU 2011-08; however, the Partnership does not expect adoption of this standard will materially impact its financial position or results of operations.

Quarterly Distributions of Available Cash. Following are distributions declared by the Partnership subsequent to December 31, 2010:

Quarter Ended	Record Date	Payment Date	Cash Distributions (per common unit)
December 31, 2010	February 7, 2011	February 14, 2011	$0.445
March 31, 2011	May 6, 2011	May 13, 2011	$0.445

June 30, 2011	August 5, 2011	August 12, 2011	$0.450
September 30, 2011	November 7, 2011	November 14, 2011	$0.455

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Common Unit Offering. In October 2011, the Partnership issued 11,500,000 common units representing limited partner interests in a public offering at a price of $20.92 per common unit, resulting in net proceeds of $231.9 million which were used to repay outstanding borrowings under the revolving credit facility.

2. Income (Loss) per Limited Partner Unit

The following tables provide a reconciliation of the numerator and denominator of the basic and diluted earnings per unit computations for the three and nine months ended September 30, 2011. For the Predecessor period from January 1, 2010 to May 25, 2010 and the Successor period from May 26, 2010 to September 30, 2010, diluted earnings per unit equaled basic earnings per unit because all instruments were antidilutive.

	Three Months Ended September 30, 2011			Three Months Ended September 30, 2010		
	Income (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
Basic income from continuing operations per unit						
Limited Partners' interest	$26,243	145,842,735	$0.18	$4,314	128,387,929	$0.03
Effect of Dilutive Securities:						
Common unit options	—	13,633		—	34,671	
Phantom units *	—	281,320		—	204,960	
Series A Preferred Units	(13,233)	4,626,197		—	—	
Diluted income from continuing operations per unit	$13,010	150,763,885	$0.09	$4,314	128,627,560	$0.03

	Nine Months Ended September 30, 2011		
	Income (Numerator)	Units (Denominator)	Per-Unit Amount
Basic income from continuing operations per unit			
Limited Partners' interest	$48,031	142,058,631	$0.34
Effect of Dilutive Securities:			
Common unit options	—	23,450	
Phantom units *	—	237,192	
Series A Preferred Units	(14,770)	4,626,197	
Diluted income from continuing operations per unit	$33,261	146,945,470	$0.23

* Amount assumes maximum conversion rate for market condition awards.

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

	Three Months Ended	
	September 30, 2011	September 30, 2010
Common unit options	—	—
Phantom units *	—	—
Series A Preferred Units	—	4,584,192

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	Successor		Predecessor
	Nine Months Ended September 30, 2011	Period from Acquisition (May 26, 2010) to September 30, 2010	Period from January 1, 2010 to May 25, 2010
Restricted (non-vested) common units	—	—	396,918
Common unit options	—	288,500	298,400
Phantom units *	—	322,602	369,346
Series A Preferred Units	—	4,584,192	4,584,192

* Amount assumes maximum conversion rate for market condition awards.

3. Investment in Unconsolidated Affiliates

Lone Star. The Partnership contributed $592.7 million in cash to Lone Star in exchange for its 30% interest on May 2, 2011. Lone Star, a newly formed joint venture that is owned 70% by ETP and 30% by the Partnership, completed its acquisition of all of the membership interest in LDH, which previously had been a wholly-owned subsidiary of Louis Dreyfus Highbridge Energy LLC, for $1.98 billion in cash. To fund a portion of this capital contribution, the Partnership issued 8,500,001 common units representing limited partnership interests with net proceeds of $203.9 million.

Lone Star owns and operates an NGL storage, fractionation and transportation business. Lone Star's storage assets are primarily located in Mont Belvieu, Texas and its West Texas Pipeline transports NGLs through an intrastate pipeline system that originates in the Permian Basin in west Texas, passes through the Barnett Shale production area in north Texas and terminates at the Mont Belvieu storage and fractionation complex. Lone Star also owns and operates fractionation and processing assets located in Louisiana.

Lone Star is managed by a two-person board of directors, with the Partnership and ETP each having the right to appoint one director, and is operated by ETP. As of September 30, 2011, the carrying value of the Partnership’s interest in Lone Star was $615.1 million. Amounts recorded with respect to Lone Star for the period ended September 30, 2011 are summarized in the table below:

	Three Months Ended September 30, 2011
Contributions to Lone Star	$24,630
Distributions received from Lone Star	18,900
Partnership's share of Lone Star's net income	9,285

	Period from Initial Contribution (May 2, 2011) to September 30, 2011
Contributions to Lone Star	$616,311
Distributions received from Lone Star	18,900
Partnership's share of Lone Star's net income	17,673

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The summarized income statement information of Lone Star (on a 100% basis) is disclosed below:

	Three Months Ended September 30, 2011
Total revenues	$146,596
Operating income	30,936
Net income	30,952

	Period from Initial Contribution (May 2, 2011) to September 30, 2011
Total revenues	$245,416
Operating income	59,079
Net income	58,910

HPC. The Partnership owns a 49.99% general partner interest in HPC. As of September 30, 2011 and December 31, 2010, the carrying value of the Partnership’s general partner interest in HPC was $686.9 million and $698.8 million, respectively. Amounts recorded with respect to HPC for the three and nine months ended September 30, 2011 and 2010, including successor and predecessor periods, are summarized in the tables below:

	Three Months Ended September 30,	
	2011	2010
Distributions received from HPC	$15,022	$32,966
Return of investment received from HPC	—	19,995
Partnership's share of HPC's net income	12,138	15,180
Amortization of excess fair value of investment in HPC	1,462	1,585

	Successor		Predecessor
	Nine Months Ended September 30, 2011	Period from Acquisition (May 26, 2010) to September 30, 2010	Period from January 1, 2010 to May 25, 2010
Contributions to HPC	$—	$ —	$ 20,210
Purchase of additional HPC Interest	—	—	75,114
Distributions received from HPC	49,863	32,966	12,446
Return of investment received from HPC	—	19,995	—
Partnership's share of HPC's net income	42,343	19,639	15,872
Amortization of excess fair value of investment in HPC	4,385	1,949	—

The summarized income statement information of HPC (on a 100% basis) is disclosed below:

	Three Months Ended September 30,	
	2011	2010
Total revenues	$43,809	$49,409
Operating income	24,627	30,507
Net income	24,282	30,366

	Nine Months Ended September 30,	
	2011	2010
Total revenues	$141,043	$128,973

Operating income	85,469	74,923
Net income	84,703	74,640

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MEP. On September 1, 2011, the Partnership purchased an additional 0.1% interest in MEP from ETP for $1.2 million in cash, bringing its total interest in MEP to 50%. Because this transaction occurred between entities under common control, partners' capital was increased by $0.2 million, which represented a deemed contribution of the excess carrying amount of ETP's investment of $1.4 million over the purchase price. As of September 30, 2011 and December 31, 2010, the carrying value of the Partnership's interest in MEP was $622.2 million and $652.5 million, respectively. Amounts recorded with respect to MEP for the three and nine months ended September 30, 2011 and 2010 are summarized in the tables below:

	Three Months Ended September 30,	
	2011	2010
Distributions received from MEP	$19,238	$ 27,176
Partnership's share of MEP's net income	10,985	8,159

	Nine Months Ended September 30, 2011	Period from Acquisition (May 26, 2010) to September 30, 2010
Distributions received from MEP	$62,897	$ 27,176
Partnership's share of MEP's net income	31,290	12,185

The summarized income statement information of MEP (on a 100% basis) is disclosed below:

	Three Months Ended September 30,	
	2011	2010
Total revenues	$65,853	$56,997
Operating income	34,852	29,100
Net income	21,998	16,351

	Nine Months Ended September 30, 2011	Period from Acquisition (May 26, 2010) to September 30, 2010
Total revenues	$195,620	$ 78,266
Operating income	101,307	40,599
Net income	62,684	24,419

4. Derivative Instruments

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

Commodity Price Risk. The Partnership is a net seller of NGLs, condensate and natural gas as a result of its gathering and processing operations. The prices of these commodities are impacted by changes in the supply and demand as well as other market forces. Both the Partnership's profitability and cash flow are affected by the inherent volatility of these commodities which could adversely affect its ability to make distributions to its unitholders. The Partnership manages this commodity price exposure through an integrated strategy that includes management of its contract portfolio, matching sales prices of commodities with purchases, optimization of its portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, the Partnership may not be able to match pricing terms or cover its risk to price exposure with financial hedges, and it may be exposed to commodity price risk. Speculative positions with derivative contracts are prohibited under the Partnership's policies. At September 30, 2011, all of the Partnership's commodity swaps were accounted for as cash flow hedges.

Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under its revolving credit facility. As of September 30, 2011, the Partnership had $445 million of outstanding borrowings exposed to variable interest rate risk. In April 2010, the Partnership entered into two-year interest rate swaps related to $250 million of borrowings under its

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revolving credit facility, effectively locking the base rate, exclusive of applicable margins, for these borrowings at 1.325% through April 2012. The Partnership accounts for these interest rate swaps using the mark-to-market method of accounting.

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

The Partnership is exposed to credit risk from its derivative counterparties. The Partnership does not require collateral from these counterparties. The Partnership deals primarily with financial institutions when entering into financial derivatives, and utilizes master netting agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership’s counterparties fail to perform under existing swap contracts, the Partnership’s maximum loss as of September 30, 2011 would be $8.2 million which would be reduced by $4 million due to the netting feature. The Partnership has elected to present assets and liabilities under master netting agreements gross on the condensed consolidated balance sheets.

Embedded Derivatives. The Series A Preferred Units contain embedded derivatives which are required to be bifurcated and accounted for separately, such as the holders’ conversion option and the Partnership’s call option. These embedded derivatives are accounted for using mark-to-market accounting. The Partnership does not expect the embedded derivatives to affect its cash flows.

Quantitative Disclosures. The Partnership expects to reclassify $5.3 million of net hedging losses to revenues from accumulated other comprehensive loss in the next 12 months.

The Partnership’s derivative assets and liabilities, including credit risk adjustments, as of September 30, 2011 and December 31, 2010 are detailed below:

	Assets		Liabilities	
	September 30, 2011	December 31, 2010	September 30, 2011	December 31, 2010
Derivatives designated as cash flow hedges:				
Current amounts				
Commodity contracts	$4,504	$2,650	$11,357	$11,421
Long-term amounts				
Commodity contracts	3,696	23	365	3,271
Total cash flow hedging instruments	8,200	2,673	11,722	14,692
Derivatives not designated as cash flow hedges:				
Current amounts				
Interest rate contracts	—	—	1,078	1,751
Long-term amounts				
Interest rate contracts	—	—	—	833
Embedded derivatives in Series A Preferred Units	—	—	36,268	57,023
Total derivatives not designated as cash flow hedges	—	—	37,346	59,607
Total derivatives	$8,200	$2,673	$49,068	$74,299

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The Partnership's statement of operations for the three months ended September 30, 2011 and 2010 were impacted by derivative instruments activities as follows:

		Three Months Ended September 30, 2011	Three Months Ended September 30, 2010
		Change in Value Recognized in AOCI on Derivatives (Effective Portion)	
Derivatives in cash flow hedging relationships:			
Commodity derivatives		$10,287	$—
	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	
Derivatives in cash flow hedging relationships:			
Commodity derivatives	Revenues	$(5,282)	$—
	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Recognized in Income on Ineffective Portion	
Derivatives in cash flow hedging relationships:			
Commodity derivatives	Revenues	$21	$—
	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Recognized in Income on Derivatives	
Derivatives not designated in a hedging relationship:			
Commodity derivatives (credit risk adjustment)	Revenues	$(119)	$(6,218)
Interest rate swap derivatives	Interest expense, net	99	(1,795)
Embedded derivatives	Other income & deductions, net	15,230	7,321
		$15,210	$(692)

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The Partnership's statement of operations for the nine months ended September 30, 2011 and 2010 were impacted by derivative instruments activities as follows:

		Successor		Predecessor
		Nine Months Ended September 30, 2011	Period from Acquisition (May 26, 2010) to September 30, 2010	Period from January 1, 2010 to May 25, 2010
		Change in Value Recognized in AOCI on Derivatives (Effective Portion)		
Derivatives in cash flow hedging relationships:				
Commodity derivatives		$(5,179)	$ —	$ 14,371
	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)		
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Revenues	$(14,276)	$ —	$ (5,200)
Interest rate swap derivatives	Interest expense, net	—	—	(1,060)
		$(14,276)	$ —	$ (6,260)
	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Recognized in Income on Ineffective Portion		
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Revenues	$(253)	$ —	$ (799)
	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) from Designation Amortized from AOCI into Income		
Derivatives not designated in a hedging relationship:				
Commodity derivatives	Revenues	$—	$ —	$ 4,115
	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Recognized in Income on Derivatives		
Derivatives not designated in a hedging relationship:				
Commodity derivatives (credit risk adjustment)	Revenues	$(107)	$ (6,348)	$ 1,168
Interest rate swap derivatives	Interest expense, net	(388)	(3,510)	(824)
Embedded derivatives	Other income & deductions, net	20,755	3,715	(4,039)
		$20,260	$ (6,143)	$ (3,695)

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5. Long-term Debt

Obligations in the form of senior notes and borrowings under the revolving credit facility are as follows:

	September 30, 2011	December 31, 2010
Senior notes	$1,355,380	$856,061
Revolving loans	445,000	285,000
Total	1,800,380	1,141,061
Less: current portion	—	—
Long-term debt	$1,800,380	$1,141,061
Availability under revolving credit facility:		
Total credit facility limit	$900,000	$900,000
Revolving loans	(445,000)	(285,000)
Letters of credit	(20,000)	(16,015)
Total available	$435,000	$598,985

Scheduled maturities of long-term debt at September 30, 2011 are as follows:

Years Ending December 31,	Amount
2011 (remainder)	$—
2012	—
2013	—
2014	445,000
2015	—
Thereafter	1,350,000 *
Total	$1,795,000

*Excludes unamortized premiums of $5.4 million as of September 30, 2011.

Revolving Credit Facility. The Partnership’s $900 million revolving credit facility expires on June 15, 2014. The revolving credit facility and guarantees are senior to the Partnership’s and each guarantor’s unsecured obligations, to the extent of the value of the assets securing such obligations. The revolving credit facility contains financial covenants requiring RGS and its subsidiaries to maintain debt to consolidated EBITDA, as defined in the credit agreement, ratio less than 5.25. At September 30, 2011, RGS and its subsidiaries were in compliance with these covenants.

The outstanding balance under the revolving credit facility bears interest at LIBOR plus a margin or alternate base rate (equivalent to the U.S. prime rate lending rate) plus a margin, or a combination of both. The weighted average interest rate on the total amount outstanding under the Partnership's revolving credit facility as of September 30, 2011 was 3.03%.

On May 2, 2011, the Partnership amended its Fifth Amended and Restated Credit Agreement to permit the acquisition of equity interests in Lone Star and to allow for additional investments in Lone Star of up to $150 million.

Senior Notes. In May 2011, the Partnership and Finance Corp. issued $500 million in senior notes that mature on July 15, 2021 (the “2021 Notes”). The 2021 Notes bear interest at 6.5% payable semi-annually in arrears on January 15 and July 15, commencing January 15, 2012. The proceeds were used to repay borrowings outstanding under the Partnership’s revolving credit facility.

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At any time prior to July 15, 2014, the Partnership may redeem up to 35% of the senior notes at a price equal to 106.5% plus accrued interest. Beginning on July 15 of the years indicated below, the Partnership may redeem all or part of the 2021 Notes at the redemption prices, expressed as percentages of the principal amount, set forth below:

July 15 of year ending:	Percentage of Redemption
2016	103.250%
2017	102.167%
2018	101.083%
2019 and thereafter at 100%	100.000%

Upon a change of control, as defined in the indenture, followed by a rating decline within 90 days, each holder of the 2021 Notes will be entitled to require the Partnership to purchase all or a portion of its notes at a purchase price of 101% plus accrued interest and liquidated damages, if any. The Partnership's ability to purchase the notes upon a change of control will be limited by the terms of our debt agreements, including the Partnership's revolving credit facility.

The 2021 Notes contain various covenants that limit, among other things, the Partnership's ability, and the ability of certain of its subsidiaries, to:

- incur additional indebtedness;
- pay distributions on, or repurchase or redeem equity interests;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets, consolidate or merge with or into other companies.

If the 2021 Notes achieve investment grade ratings by both Moody's and S&P and no default or event of default has occurred and is continuing, the Partnership and its subsidiaries guarantors will no longer be subject to many of the foregoing covenants. At September 30, 2011, the Partnership and its subsidiaries guarantors were in compliance with these covenants.

Finance Corp., co-issuer for all of the Partnership’s senior notes, has no operations and will not have revenues other than as may be incidental. Since the Partnership has no independent operations, the guarantees are fully unconditional and joint and several of its existing unconsolidated subsidiaries, except for one minor subsidiary, and the Partnership has not included condensed consolidated financial information of guarantors of the senior notes.

6. Commitments and Contingencies

Legal. The Partnership is involved in various claims, lawsuits and audits by taxing authorities incidental to its business. These claims and lawsuits in the aggregate are not expected to have a material adverse effect on the Partnership’s business, financial condition, results of operations or cash flows.

Keyes Litigation. In August 2008, Keyes Helium Company, LLC (“Keyes”) filed suit against RGS, the Partnership, the General Partner and various other subsidiaries. Keyes entered into an output contract with the Partnership’s predecessor-in-interest in 1996 under which it purchased all of the helium produced at the Lakin, Kansas processing plant. In September 2004, the Partnership decided to shut down its Lakin plant and contract with a third party for the processing of volumes processed at Lakin; as a result, the Partnership no longer delivered any helium to Keyes. In its suit, Keyes alleges it is entitled to damages for the costs of covering its purchases of helium. On May 7, 2010, the jury rendered a verdict in favor of the Partnership. No damages were awarded to the Plaintiffs. Plaintiffs have appealed the verdict. The hearing on appeal will likely take place in the first quarter of 2012.

7. Series A Preferred Units

On September 2, 2009, the Partnership issued 4,371,586 Series A Preferred Units. As of September 30, 2011, the Series A Preferred Units were convertible to 4,626,197 common units, and if outstanding, are mandatorily redeemable on September 2, 2029 for $80 million plus all accrued but unpaid distributions thereon. The Series A Preferred Units receive fixed quarterly cash distributions of $0.445 per unit beginning with the quarter ended March 31, 2010, if outstanding on the record dates of the Partnership’s common unit distributions. Effective as of March 2, 2010, holders can elect to convert Series A Preferred Units to common units at any time in accordance with the partnership agreement.

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The following table provides a reconciliation of the beginning and ending balances of the Series A Preferred Units for the nine months ended September 30, 2011:

	Units	Amount	
Outstanding at beginning of period	4,371,586	$70,943	
Accretion to redemption value	—	148	
Outstanding at end of period	4,371,586	$71,091	*

* This amount will be accreted to $80 million plus any accrued and unpaid distributions by deducting amounts from partners' capital over the remaining period until the mandatory redemption date of September 2, 2029.

8. Related Party Transactions

As of September 30, 2011 and December 31, 2010, details of the Partnership's related party receivables and related party payables were as follows:

	September 30, 2011	December 31, 2010
Related party receivables		
EPD and its subsidiaries	$31,285	$25,539
HPC	1,162	5,823
ETE and its subsidiaries	2,281	970
Other	22	10
Total related party receivables	$34,750	$32,342
Related party payables		
EPD and its subsidiaries	$1,199	$1,323
HPC	355	760
ETE and its subsidiaries	10,066	1,245
Other	13	10
Total related party payables	$11,633	$3,338

Transactions with ETE and its subsidiaries. Under a May 26, 2010 service agreement with Services Co., Services Co. performs certain services for the Partnership. The Partnership pays Services Co.'s direct expenses for these services, plus an annual fee of $10 million, and receives the benefit of any cost savings recognized for these services. The services agreement has a five year term from May 26, 2010 to May 26, 2015, subject to earlier termination rights in the event of a change in control, the failure to achieve certain cost savings for the Partnership or upon an event of default. Also, the Partnership, together with Regency GP LP and RGS entered into an operation and service agreement (the "Operations Agreement") with ETC. Under the Operations Agreement, ETC will perform certain operations, maintenance and related services reasonably required to operate and maintain certain facilities owned by the Partnership. Pursuant to the Operations Agreement, the Partnership will reimburse ETC for actual costs and expenses incurred in connection with the provision of these services based on an annual budget agreed-upon by both parties. The Operations Agreement has an initial term of one year and automatically renews on a year-to-year basis upon expiration of the initial term.

The total fees related to these service contracts were $4.2 million and $12.4 million for the three and nine months ended September 30, 2011, respectively, $2.5 million for the three months ended September 30, 2010, and $3.3 million for the period from the acquisition, May 26, 2010 to September 30, 2010.

In conjunction with distributions by the Partnership to the limited and general partner interests, ETE received cash distributions of $14.4 million and $42.5 million during the three and nine months ended September 30, 2011, respectively, and $13.7 million for the period from May 26, 2010 to September 30, 2010.

The Partnership's Contract Compression segment provides contract compression services to subsidiaries of ETP and records revenue in gathering, transportation and other fees on the statement of operations. The Partnership's Contract Compression segment sold compression equipment to a subsidiary of ETP for $1.6 million and $7.9 million for the three and nine months ended September 30, 2011, respectively. As these transactions are between entities under common control, partners' capital was increased by $66 thousand, which represented a deemed contribution of the excess sales price over the carrying amounts. The Partnership's

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Contract Compression segment purchased compression equipment from a subsidiary of ETP for $6.2 million and $24.3 million for the three and nine months ended September 30, 2011, respectively.

On September 1, 2011, the Partnership purchased an additional 0.1% interest in MEP from ETP for $1.2 million in cash, bringing its total interest in MEP to 50%. Because this transaction occurred between entities under common control, partners' capital was increased by $0.2 million, which represented a deemed contribution of the excess carrying amount of ETP's investment of $1.4 million over the purchase price.

Prior to December 31, 2010, the employees operating the assets of the Partnership and its subsidiaries and all those providing staff or support services were employees of the General Partner. Pursuant to the Partnership agreement, the General Partner receives a monthly reimbursement for all direct and indirect expenses incurred on behalf of the Partnership. Effective January 1, 2011, certain employees of the Partnership became employees of ETP, and the Partnership reimburses ETP for all direct and indirect expenses incurred on behalf of the Partnership related to those employees. Reimbursements of $12.6 million, $47 million, $18 million, $23.6 million and $31.1 million were recorded to the General Partner during the three and nine months ended September 30, 2011, the three months ended September 30, 2010, from May 26, 2010 to September 30, 2010, and from January 1, 2010 to May 25, 2010, respectively, in the Partnership's financial statements as operating expenses or general and administrative expenses. For the three and nine months ended September 30, 2011, reimbursements of $6.2 million and $14.8 million to ETP were recorded in the Partnership's financial statements as operating expenses or general and administrative expenses.

Transactions with HPC. Under a master services agreement with HPC, the Partnership operates and provides all employees and services for the operation and management of HPC. During the three and nine months ended September 30, 2011, the three months ended September 30, 2010, from May 26, 2010 to September 30, 2010, and from January 1, 2010 to May 25, 2010, the related party general and administrative expenses reimbursed to the Partnership were $4.2 million, $12.6 million, $4.2 million, $5.6 million and $6.9 million, respectively, which is recorded in gathering, transportation and other fees on the statement of operations.

The Partnership's Contract Compression segment provides contract compression services to HPC and records revenues in gathering, transportation and other fees in the statement of operations. The Partnership also receives transportation services from HPC and records it as cost of sales.

Transactions with EDP and its subsidiaries. EPD owns a portion of ETE's outstanding common units; therefore, it is considered a related party along with any of its subsidiaries. The Partnership, in the ordinary course of business, sells natural gas and NGLs to subsidiaries of EPD and records the revenues in gas sales and NGL sales. The Partnership also incurs NGL processing fees and transportation fees with subsidiaries of EPD and records these fees as cost of sales.

9. Segment Information

During the nine months ended September 30, 2011, the Partnership changed the name of the Transportation segment to Joint Ventures, which represents the Partnership's equity method investments in its three unconsolidated affiliates: HPC, MEP and Lone Star. In addition, the disposition of the east Texas assets in July 2010 impacts the Gathering and Processing segment, as the results of those operations are now presented within discontinued operations and excluded from the segment information table. Also, operations within the Partnership's Contract Treating segment for the current year were presented in the Partnership's Contract Compression segment in the prior year. Accordingly, the Partnership has recast the segment information for the corresponding periods in 2010.

Gathering and Processing. The Partnership provides "wellhead-to-market" services to producers of natural gas, which include gathering raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate NGLs from the raw natural gas and selling or delivering pipeline-quality natural gas and NGLs to various markets and pipeline systems.

Joint Ventures. The Partnership owns a 49.99% general partner interest in HPC, which delivers natural gas from northwest Louisiana to downstream pipelines and markets through the 450 mile Regency Intrastate Gas pipeline system. The Partnership owns a 50% membership interest in MEP, which owns approximately 500 miles of natural gas pipeline stretching from southeast Oklahoma through northeast Texas, northern Louisiana and central Mississippi into Alabama. The Partnership owns a 30% membership interest in Lone Star, an entity owning a diverse set of midstream energy assets including pipelines, storage and processing facilities located in the states of Texas, Mississippi and Louisiana.

Contract Compression. The Partnership owns and operates a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems.

Contract Treating. The Partnership owns and operates a fleet of equipment used to provide treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling, dehydration and BTU management, to natural gas producers and midstream pipeline companies.

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Corporate and Others. The Corporate and Others segment comprises a 10-mile interstate pipeline and the Partnership's corporate offices.

The Partnership accounts for intersegment revenues as if the revenues were to third parties, exclusive of certain cost of capital charges.

Management evaluates the performance of each segment and makes capital allocation decisions through the separate consideration of segment margin and operation and maintenance expenses. Segment margin for the Gathering and Processing and the Corporate and Others segments is defined as total revenues, including service fees, less cost of sales. In the Contract Compression segment and Contract Treating segment, segment margin is defined as revenues less direct costs.

Management believes segment margin is an important measure because it directly relates to volume, commodity price changes, revenue generating horsepower and revenue generating gallons per minute. Operation and maintenance expenses are a separate measure used by management to evaluate performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of operation and maintenance expenses. These expenses fluctuate depending on the activities performed during a specific period. The Partnership does not deduct operation and maintenance expenses from total revenues in calculating segment margin because management separately evaluates commodity volume and price changes in segment margin. The Partnership does not record segment margin for the Joint Ventures segment because it records its ownership percentages of the net income in HPC, MEP and Lone Star as income from unconsolidated affiliates in accordance with the equity method of accounting.

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Results for each period, together with amounts related to balance sheets for each segment, are shown below:

	Three Months Ended	
	September 30, 2011	September 30, 2010
External Revenues		
Gathering and Processing	$339,273	$253,054
Joint Ventures	—	—
Contract Compression	36,024	36,172
Contract Treating	10,573	3,299
Corporate and Others	4,397	4,363
Eliminations	—	—
Total	$390,267	$296,888
Intersegment Revenues		
Gathering and Processing	$—	$—
Joint Ventures	—	—
Contract Compression	3,339	5,869
Contract Treating	20	—
Corporate and Others	60	93
Eliminations	(3,419)	(5,962)
Total	$—	$—
Segment Margin		
Gathering and Processing	$64,716	$42,723
Joint Ventures	—	—
Contract Compression	37,957	38,509
Contract Treating	6,642	2,730
Corporate and Others	4,767	5,763
Eliminations	(3,341)	(5,869)
Total	$110,741	$83,856
Operation and Maintenance		
Gathering and Processing	$24,426	$23,978
Joint Ventures	—	—
Contract Compression	15,916	15,768
Contract Treating	902	322
Corporate and Others	41	107
Eliminations	(3,335)	(5,869)
Total	$37,950	$34,306

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	Successor		Predecessor
	Nine Months Ended September 30, 2011	Period from Acquisition (May 26, 2010) to September 30, 2010	Period from January 1, 2010 to May 25, 2010
External Revenues			
Gathering and Processing	$908,448	$ 336,832	$ 438,804
Joint Ventures	—	—	—
Contract Compression	112,532	48,226	58,971
Contract Treating	29,848	3,299	—
Corporate and Others	13,189	5,511	7,275
Eliminations	—	—	—
Total	$1,064,017	$ 393,868	$ 505,050
Intersegment Revenues			
Gathering and Processing	$—	$ —	$ —
Joint Ventures	—	—	—
Contract Compression	12,809	7,867	9,126
Contract Treating	20	—	—
Corporate and Others	237	115	91
Eliminations	(13,066)	(7,982)	(9,217)
Total	$—	$ —	$ —
Segment Margin			
Gathering and Processing	$169,011	$ 57,096	$ 85,997
Joint Ventures	—	—	—
Contract Compression	116,370	50,997	62,356
Contract Treating	21,594	2,730	—
Corporate and Others	14,582	7,706	8,045
Eliminations	(12,802)	(7,867)	(9,126)
Total	$308,755	$ 110,662	$ 147,272
Operation and Maintenance			
Gathering and Processing	$67,250	$ 31,441	$ 33,430
Joint Ventures	—	—	—
Contract Compression	48,618	20,692	23,476
Contract Treating	2,311	322	—
Corporate and Others	129	120	59
Eliminations	(12,802)	(7,867)	(9,123)
Total	$105,506	$ 44,708	$ 47,842

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The tables below provide a reconciliation of total segment margin to income from continuing operations before income taxes:

	Three Months Ended	
	September 30, 2011	September 30, 2010
Total segment margin	$110,741	$83,856
Operation and maintenance	(37,950)	(34,306)
General and administrative	(17,350)	(18,072)
Gain (loss) on asset sales, net	131	(200)
Depreciation and amortization	(41,956)	(32,205)
Income from unconsolidated affiliates	30,946	21,754
Interest expense, net	(28,852)	(20,379)
Other income and deductions, net	15,050	7,524
Income from continuing operations before income taxes	$30,760	$7,972

	Successor		Predecessor
	Nine Months Ended September 30, 2011	Period from Acquisition (May 26, 2010) to September 30, 2010	Period from January 1, 2010 to May 25, 2010
Total segment margin	$308,755	$ 110,662	$ 147,272
Operation and maintenance	(105,506)	(44,708)	(47,842)
General and administrative	(54,010)	(25,176)	(37,212)
Loss on asset sales, net	(50)	(210)	(303)
Depreciation and amortization	(122,695)	(42,750)	(41,784)
Income from unconsolidated affiliates	86,921	29,875	15,872
Interest expense, net	(73,548)	(28,460)	(36,321)
Other income and deductions, net	20,105	4,003	(3,897)
Income (loss) from continuing operations before income taxes	$59,972	$ 3,236	$ (4,215)

The table below provides a listing of assets reflected in the consolidated balance sheet for each segment:

	September 30, 2011	December 31, 2010
Gathering and Processing	$1,903,285	$1,724,682
Joint Ventures	1,924,183	1,351,256
Contract Compression	1,402,686	1,411,325
Contract Treating	216,597	220,584
Corporate and Others	78,988	62,357
Total	$5,525,739	$4,770,204

10. Equity-Based Compensation

The Partnership's LTIP for its employees, directors and consultants authorizes grants up to 2,865,584 common units. LTIP compensation expense of $0.7 million, $2.4 million, $0.3 million, $0.4 million and $12.1 million is recorded in general and administrative expense in the statement of operations for the three and nine months ended September 30, 2011, for the three months ended September 30, 2010, from May 26, 2010 to September 30, 2010, and from January 1, 2010 to May 25, 2010, respectively.

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Common Unit Options. The common unit options activity during the nine months ended September 30, 2011 is as follows:

Common Unit Options	Units	Weighted Average Exercise Price	Weighted Average Contractual Term (Years)	Aggregate Intrinsic Value *
Outstanding at beginning of period	201,950	$ 21.93		
Granted	—	—		
Exercised	(38,300)	20.84		$ 224
Forfeited or expired	(6,800)	26.72		
Outstanding at end of period	156,850	21.99	4.6	200
Exercisable at end of period	156,850			200

* Intrinsic value equals the closing market price of a unit less the option strike price, multiplied by the number of unit options outstanding as of the end of the period presented. Unit options with an exercise price greater than the end of the period closing market price are excluded.

During the nine months ended September 30, 2011, the Partnership received $0.8 million in proceeds from the exercise of unit options.

Phantom Units. All phantom units granted prior to November 2010 were in substance two grants composed of (1) service condition grants with graded vesting over three years and (2) market condition grants with cliff vesting based upon the Partnership's relative ranking in total unitholder return among 20 peer companies. Distributions related to these unvested phantom units will be accrued and paid upon vesting. All phantom units granted after November 2010 were service condition grants only with graded vesting over five years. Distributions related to these unvested phantom units will be paid concurrent with the Partnership's distribution for common units.

The following table presents phantom units activity for the nine months ended September 30, 2011:

Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at beginning of period	742,517	$ 23.61
Service condition grants	76,745	26.07
Market condition grants	—	—
Vested service condition	(20,980)	20.69
Vested market condition	(8,550)	19.52
Forfeited service condition	(67,807)	25.06
Forfeited market condition	(8,700)	19.52
Outstanding at end of period	713,225	24.78

The Partnership expects to recognize $12 million of compensation expense related to non-vested phantom units over a period of 4.0 years.

11. Fair Value Measures

The fair value measurement provisions establish a three-tiered fair value hierarchy that prioritizes inputs to valuation techniques used in fair value calculations. The three levels of inputs are defined as follows:

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

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

The Partnership's financial assets and liabilities measured at fair value on a recurring basis are derivatives related to interest rate and commodity swaps and embedded derivatives in the Series A Preferred Units. Derivatives related to interest rate and commodity swaps are valued using discounted cash flow techniques. These techniques incorporate Level 1 and Level 2 inputs such as future interest rates and commodity prices. These market inputs are utilized in the discounted cash flow calculation considering the instrument's term, notional amount, discount rate and credit risk and are classified as Level 2 in the hierarchy. Derivatives related to Series A Preferred Units are valued using a binomial lattice model. The market inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, common unit price, dividend yield, and expected volatility, and are classified as Level 3 in the hierarchy.

The following table presents the Partnership's derivative assets and liabilities measured at fair value on a recurring basis:

	Fair Value Measurements at September 30, 2011			Fair Value Measurements at December 31, 2010		
	Fair Value Total	Significant Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Fair Value Total	Significant Observable Inputs (Level 2)	Unobservable Inputs (Level 3)
Assets:						
Commodity Derivatives:						
Natural Gas	$2,806	$2,806	$—	$ 2,481	$ 2,481	$—
NGLs	577	577	—	192	192	—
Condensate	4,817	4,817	—	—	—	—
Total Assets	$8,200	$8,200	$—	$ 2,673	$ 2,673	$—
Liabilities:						
Interest Rate Derivatives	$1,078	$1,078	$—	$ 2,584	$ 2,584	$—
Commodity Derivatives:						
Natural Gas	—	—	—	427	427	—
NGLs	11,722	11,722	—	10,684	10,684	—
Condensate	—	—	—	3,581	3,581	—
Embedded Derivatives in Series A Preferred Units	36,268	—	36,268	57,023	—	57,023
Total Liabilities	$49,068	$12,800	$ 36,268	$ 74,299	$ 17,276	$ 57,023

The following table presents the changes in Level 3 derivatives measured on a recurring basis for the nine months ended September 30, 2011. There were no transfers between the fair value hierarchy levels for the nine months ended September 30, 2011.

Balance at beginning of period	$57,023	
Net unrealized gain included in other income and deductions, net	(20,755	)
Balance at end of period	$36,268	

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. Long-term debt, other than the senior notes, is comprised of borrowings under which interest accrues under a floating interest rate structure. Accordingly, the carrying value approximates fair value. The estimated fair value of the 2016 Notes, based on third party market value quotations as of September 30, 2011 and December 31, 2010 was $270.6 million and $274.4 million, respectively. The estimated fair value of the 2018 Notes, based on third party market value quotations as of September 30, 2011 and December 31, 2010 was $618 million and $607.5 million, respectively. The estimated fair value of the 2021 Notes, based on third party market value quotations as of September 30, 2011 was $495 million.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations
(Tabular dollar amounts are in thousands)
The following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our historical consolidated financial statements and the notes included elsewhere in this document.
OVERVIEW. We are a growth-oriented publicly-traded Delaware limited partnership formed in 2005 engaged in gathering and processing, contract compression, treating, transportation, fractionation and storage of natural gas and NGLs. We focus on providing midstream services in some of the most prolific natural gas producing regions in the United States, including the Haynesville, Eagle Ford, Barnett, Fayetteville, and Marcellus shales as well as the Permian Delaware basin. Our assets are located in California, Louisiana, Texas, Arkansas, Pennsylvania, Mississippi, Alabama and the mid-continent region of the United States, which includes Kansas, Colorado and Oklahoma.
RECENT DEVELOPMENTS
Common Unit Offering. In October 2011, we issued 11,500,000 common units representing limited partner interests in a public offering at a price of $20.92 per common unit, resulting in net proceeds of $231.9 million which were used to repay outstanding borrowings under our revolving credit facility.
Eagle Ford Expansion. In June 2011, we entered into agreements to provide gas and condensate gathering services for a producer in the Eagle Ford Shale and to construct facilities to perform these services, including a wellhead gathering system, at an expected cost of $450 million. The expansion will be owned and operated by us and will tie into our existing gathering system. In addition, we have purchased certain existing midstream assets located in the Eagle Ford Shale as part of this expansion. The expansion will be completed in phases and is scheduled for completion by 2014.
Lone Star Expansion. Lone Star announced a construction project of a 100,000 Bbls/d fractionator and related storage services and interconnectivity infrastructure to be constructed in Mont Belvieu, Texas, which we expect to complete in early 2013. Our estimated capital expenditures for this project are $118 million.
Lone Star announced it would construct an approximate 570-mile natural gas liquids pipeline that extends from Winkler County in west Texas to a processing plant in Jackson County, Texas. This pipeline will have a minimum capacity of approximately 209,000 Bbls/d. In connecting with this project, Lone Star has secured capacity on ETP's recently announced NGL pipeline from Jackson County to Mont Belvieu, Texas. Our estimated capital expenditures for this project are $275 million.
Cash Distributions. In July 2011, we raised our quarterly cash distribution from $0.445 to $0.45 per common unit. In October, we raised our quarterly cash distribution again, from $0.45 to $0.455 ($1.82 annualized), per common unit.
OUR OPERATIONS. We divide our operations into five business segments:

- Gathering and Processing. We provide "wellhead-to-market" services to producers of natural gas, which include gathering raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate NGLs and selling or delivering pipeline-quality natural gas and NGLs to various markets and pipeline systems.
- Joint Ventures. We own a 49.99% general partner interest in HPC, which owns RIGS, a 450 mile intrastate pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets. We own a 50% interest in MEP, which owns an interstate natural gas pipeline with approximately 500 miles stretching from southeast Oklahoma through northeast Texas, northern Louisiana and central Mississippi to an interconnect with the Transcontinental Gas Pipe Line system in Butler, Alabama. We own a 30% interest in Lone Star, an entity owning a diverse set of midstream energy assets including pipelines, storage, fractionation and processing facilities located in the states of Texas, Mississippi and Louisiana.
- Contract Compression. We own and operate a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems.
- Contract Treating. We own and operate a fleet of equipment used to provide treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling, dehydration and BTU management to natural gas producers and midstream pipeline companies.
- Corporate and Others. Our Corporate and Others segment comprises a small interstate pipeline and our corporate offices.

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HOW WE EVALUATE OUR OPERATIONS. Management uses a variety of financial and operational measurements to analyze our performance. We view these measures as important tools for evaluating the success of our operations and review these measurements on a monthly basis for consistency and trend analysis. These measures include volumes, segment margin, total segment margin, adjusted segment margin, adjusted total segment margin, operating and maintenance expense, EBITDA, and adjusted EBITDA on a segment and company-wide basis.

Volumes. We must continually obtain new supplies of natural gas to maintain or increase throughput volumes on our gathering and processing systems. Our ability to maintain existing supplies of natural gas and obtain new supplies is affected by (i) the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to our gathering and processing systems, (ii) our ability to compete for volumes from successful new wells in other areas and (iii) 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.

Segment Margin and Total Segment Margin. We define segment margin, generally, as revenues minus cost of sales. We calculate our Gathering and Processing segment margin and Corporate and Others segment margin as revenues generated from operations less the cost of natural gas and NGLs purchased and other cost of sales, including third-party transportation and processing fees.

We do not record segment margin for the Joint Ventures segment because we record our ownership percentages of the net income in HPC, MEP and Lone Star as income from unconsolidated affiliates in accordance with the equity method of accounting.

We calculate our Contract Compression segment margin as revenues minus direct costs, primarily compressor unit repairs, associated with those revenues.

We calculate our Contract Treating segment margin as revenues minus direct costs associated with those revenues.

We calculate total segment margin as the sum of segment margin of our five segments, less intersegment eliminations.

Adjusted Segment Margin and Adjusted Total Segment Margin. We define adjusted segment margin as segment margin adjusted for non-cash (gains) losses from commodity derivatives. Our adjusted total segment margin equals the sum of our operating segments' adjusted segment margins or segment margins, including intersegment eliminations. Adjusted segment margin and adjusted total segment margin are included as supplemental disclosures because they are primary performance measures used by management as they represent the results of our revenues and cost of revenues, a key component of our operations.

Revenue Generating Horsepower. Revenue generating horsepower is the primary driver for revenue growth in our Contract Compression segment, and it is also the primary measure for evaluating our operational efficiency. Revenue generating horsepower is the total horsepower that our Contract Compression segment owns and operates for external customers. It does not include horsepower under contract that is not generating revenue or idle horsepower.

Revenue Generating Gallons per Minute (GPM). Revenue generating GPM is the primary driver for revenue growth of our Contract Treating segment. GPM is used as a measure of the treating capacity of an amine plant. Revenue generating GPM is our total GPM under contract less GPM that is not generating revenue.

Operation and Maintenance Expense. Operation and maintenance expense is a separate measure that we use to evaluate operating performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of our operating and maintenance expense. 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 operation and maintenance expenses from total revenues in calculating segment margin because we separately evaluate commodity volume and price changes in segment margin.

EBITDA and Adjusted EBITDA. We define EBITDA as net income (loss) plus interest expense, net, income tax expense, net, and depreciation and amortization expense. We define adjusted EBITDA as EBITDA plus or minus the following:

- non-cash loss (gain) from commodity and embedded derivatives;
- non-cash unit based compensation;
- loss (gain) on asset sales, net;
- loss on debt refinancing;

- other non-cash (income) expense, net;
- net income attributable to noncontrolling interest; and
- the Partnership’s interest in adjusted EBITDA from unconsolidated affiliates less income from unconsolidated affiliates.

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These measures are used as supplemental measures by our management and by external users of our financial statements such as investors, 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.

Neither EBITDA nor adjusted EBITDA should be considered as an alternative to, or more meaningful than, 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 presents a reconciliation of EBITDA and adjusted EBITDA to net cash flows provided by operating activities and to net income (loss) for the Partnership:

	Successor		Predecessor
	Nine Months Ended September 30, 2011	Period from Acquisition (May 26, 2010) to September 30, 2010	Period from January 1, 2010 to May 25, 2010
Reconciliation of "Adjusted EBITDA" to net cash flows provided by operating activities and net income (loss)			
Net cash flows provided by operating activities	$204,416	$ 38,482	$ 89,421
Add (deduct):			
Depreciation and amortization, including debt issuance cost amortization and bond premium amortization	(127,079)	(44,767)	(49,363)
Write-off of debt issuance costs	—	—	(1,780)
Amortization of excess fair value of unconsolidated affiliates	(4,385)	—	—
Equity in earnings of unconsolidated affiliates	91,306	29,875	15,872
Derivative valuation change	21,660	(14,837)	(12,004)
Loss on asset sales, net	(50)	(190)	(303)
Unit-based compensation expenses	(2,444)	(440)	(12,070)
Trade accounts receivable, accrued revenues and related party receivables	13,298	(13,307)	11,272
Other current assets	(186)	(903)	(2,516)
Trade accounts payable, accrued cost of gas and liquids, related party payables and deferred revenues	(20,467)	30,026	(8,649)
Other current liabilities	(24,833)	8,186	(22,614)
Distributions received from unconsolidated affiliates	(91,306)	(29,875)	(12,446)
Other assets and liabilities	61	701	234
Net income (loss)	59,991	2,951	(4,946)
Add (deduct):			
Interest expense, net	73,548	28,502	36,459
Depreciation and amortization expense	122,695	43,424	46,084
Income tax (benefit) expense	(19)	695	404
EBITDA	256,215	75,572	78,001
Add (deduct):			
Non-cash (gain) loss from commodity and embedded derivatives	(20,149)	12,502	11,189
Non-cash unit-based compensation expense	2,687	416	11,925
Loss on asset sales, net	50	210	303
Income from unconsolidated affiliates	(86,921)	(29,875)	(15,872)
Partnership's interest in HPC's adjusted EBITDA	55,660	25,456	21,184
Partnership's interest in MEP's adjusted EBITDA	76,604	31,587	—
Partnership's interest in Lone Star's adjusted EBITDA	23,736	—	—
Other (income) expense, net	(413)	537	2,064
Adjusted EBITDA	$307,469	$ 116,405	$ 108,794

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The following table presents a reconciliation of net income to EBITDA and adjusted EBITDA for HPC and represents 100% of HPC's consolidated results of operations:

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Net income	$84,703	$74,640
Add:		
Depreciation and amortization	25,846	23,323
Interest expense, net	782	355
EBITDA	111,331	98,318
Add (deduct):		
Other expense (income), net	16	(137)
Adjusted EBITDA	$111,347	$98,181

The following table presents a reconciliation of net income to EBITDA and adjusted EBITDA for MEP and represents 100% of MEP's consolidated results of operations:

	Nine Months Ended September 30, 2011	Period from Acquisition (May 26, 2010) to September 30, 2010
Net income	$62,684	$ 24,419
Add:		
Depreciation and amortization	52,176	22,702
Interest expense, net	38,623	16,180
Adjusted EBITDA	$153,483	$ 63,301

The following table presents a reconciliation of net income to EBITDA and adjusted EBITDA for Lone Star and represents 100% of Lone Star's consolidated results of operations:

	Period from Initial Contribution (May 2, 2011) to September 30, 2011
Net income	$58,910
Add:	
Depreciation and amortization	20,043
Other expenses, net	169
Adjusted EBITDA	$79,122

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The following tables present a reconciliation of total segment margin and adjusted total segment margin to net income (loss) for the three and nine month periods ended September 30, 2011 and 2010 for the Partnership:

	Three Months Ended	
	September 30, 2011	September 30, 2010
Net income	$30,849	$7,846
Add (deduct):		
Operation and maintenance	37,950	34,306
General and administrative	17,350	18,072
Loss on asset sales, net	(131)	200
Depreciation and amortization	41,956	32,205
Income from unconsolidated affiliates	(30,946)	(21,754)
Interest expense, net	28,852	20,379
Other income and deductions, net	(15,050)	(7,524)
Income tax expense	(89)	450
Discontinued operations	—	(324)
Total segment margin	110,741	83,856
Add:		
Non-cash loss from commodity derivatives	174	13,967
Adjusted total segment margin	$110,915	$97,823

	Successor		Predecessor
	Nine Months Ended September 30, 2011	Period from Acquisition (May 26, 2010) to September 30, 2010	Period from January 1, 2010 to May 25, 2010
Net income (loss)	$59,991	$ 2,951	$ (4,946)
Add (deduct):			
Operation and maintenance	105,506	44,708	47,842
General and administrative	54,010	25,176	37,212
Loss on asset sales, net	50	210	303
Depreciation and amortization	122,695	42,750	41,784
Income from unconsolidated affiliates	(86,921)	(29,875)	(15,872)
Interest expense, net	73,548	28,460	36,321
Other income and deductions, net	(20,105)	(4,003)	3,897
Income tax expense	(19)	695	404
Discontinued operations	—	(410)	327
Total segment margin	308,755	110,662	147,272
Add:			
Non-cash loss from commodity derivatives	606	16,217	7,150
Adjusted total segment margin	$309,361	$ 126,879	$ 154,422

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RESULTS OF OPERATIONS

Three Months Ended September 30, 2011 vs. Three Months Ended September 30, 2010

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Change	Percent
Total revenues	$390,267	$296,888	$93,379	31 %
Cost of sales	279,526	213,032	(66,494)	31
Total segment margin (1)	110,741	83,856	26,885	32
Operation and maintenance	37,950	34,306	(3,644)	11
General and administrative	17,350	18,072	722	4
(Gain) loss on asset sales, net	(131)	200	331	166
Depreciation and amortization	41,956	32,205	(9,751)	30
Operating income (loss)	13,616	(927)	14,543	N/M
Income from unconsolidated affiliates	30,946	21,754	9,192	42
Interest expense, net	(28,852)	(20,379)	(8,473)	42
Other income and deductions, net	15,050	7,524	7,526	100
Income from continuing operations before income taxes	30,760	7,972	22,788	286
Income tax (benefit) expense	(89)	450	539	120
Net income from continuing operations	30,849	7,522	23,327	310
Discontinued operations	—	324	(324)	100
Net income	30,849	7,846	23,003	293
Net income attributable to noncontrolling interest	(549)	(58)	(491)	847
Net income attributable to Regency Energy Partners LP	$30,300	$7,788	$22,512	289
Gathering and processing segment margin	$64,716	$42,723	$21,993	51
Non-cash loss from commodity derivatives	174	13,967	(13,793)	99
Adjusted gathering and processing segment margin	64,890	56,690	8,200	14
Contract compression segment margin (2) (3)	37,957	38,509	(552)	1
Contract treating segment margin (2)	6,642	2,730	3,912	143
Corporate and others segment margin	4,767	5,763	(996)	17
Intersegment eliminations (3)	(3,341)	(5,869)	2,528	43
Adjusted total segment margin	$110,915	$97,823	$13,092	13 %

(1) For a reconciliation of segment margin to the most directly comparable financial measure calculated and presented in accordance with GAAP, see the reconciliation provided above.

(2) Segment margin differs from previously disclosed amounts due to the functional reorganization of our operating segments.

(3) Contract Compression segment margin includes intersegment revenues of $3.3 million and $5.9 million for the three months ended September 30, 2011 and 2010, respectively. These intersegment revenues were eliminated upon consolidation.

N/M Not meaningful.

Net Income Attributable to Regency Energy Partners LP. Our income increased to $30.3 million for the three months ended September 30, 2011 from $7.8 million for the three months ended September 30, 2010. The major components of this change were as follows:

- $26.9 million increase in total segment margin primarily due to a $22 million increase in Gathering and Processing segment margin related to additional volumes in the Eagle Ford Shale and west Texas and a $3.9 million increase related to the addition of the Contract Treating segment that was acquired in September 2010;
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$9.2 million increase in income from unconsolidated affiliates primarily from the acquisition of a 30% interest in Lone Star in May 2011;

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- $7.5 million increase in other income due to the mark-to-market gain on the embedded derivatives related to the Series A Preferred Units; offset by
- $9.8 million increase in depreciation and amortization expense primarily related to the completion of various organic growth projects since September 2010;
- $8.5 million increase in interest expense primarily related to the interest associated with the $500 million 2021 Senior Notes issued in May 2011; and
- $3.6 million increase in operation and maintenance expense primarily due to an increase in labor costs primarily due to higher short term incentives accrual, pipeline maintenance expense in the south Texas region of our Gathering and Processing segment and consumable products expense.

Adjusted Total Segment Margin. Adjusted total segment margin increased to $110.9 million in the three months ended September 30, 2011 from $97.8 million in the three months ended September 30, 2010. The major components of this change were as follows:

- Adjusted Gathering and Processing segment margin increased to $64.9 million during the three months ended September 30, 2011 from $56.7 million for the three months ended September 30, 2010 primarily due to volume growth in the Eagle Ford Shale and west Texas. Total Gathering and Processing throughput increased to 1,293,000 MMBtu/d during the three months ended September 30, 2011 from 951,000 MMBtu/d during the three months ended September 30, 2010. Total NGL gross production increased to 35,000 Bbls/d during the three months ended September 30, 2011 from 27,000 Bbls/d during the three months ended September 30, 2010;
- Contract Compression segment margin decreased to $38 million in the three months ended September 30, 2011 from $38.5 million in the three months ended September 30, 2010, which was primarily due to the decrease in intersegment transactions with the Gathering and Processing segment as a result of the transfer of certain compression units from the Contract Compression segment to the Gathering and Processing segment in the second quarter of 2011. The decrease was partially offset by an increase in revenue generating horsepower from external customers. As of September 30, 2011, our Contract Compression segment's total revenue generating horsepower was 769,000 compared to 754,000 as of September 30, 2010;
- Contract Treating segment margin increased to $6.6 million for the three months ended September 30, 2011 from $2.7 million for the three months ended September 30, 2010. We acquired the Contract Treating segment in September 2010. Revenue generating GPM as of September 30, 2011 and September 30, 2010 was 3,468 and 3,093, respectively; and
- Intersegment eliminations decreased to $3.3 million in the three months ended September 30, 2011 from $5.9 million in the three months ended September 30, 2010. The decrease was primarily due to a decrease in transactions between the Gathering and Processing and the Contract Compression segments as a result of the transfer of certain compression units from the Contract Compression segment to the Gathering and Processing segment in the third quarter of 2011.

Operation and Maintenance. Operation and maintenance expense increased to $38 million in the three months ended September 30, 2011 from $34.3 million during the three months ended September 30, 2010. The change was primarily due to the following:

- $1.7 million increase primarily due to higher short term incentives accrual;
- $0.7 million increase in pipeline maintenance expense in the south Texas region of our Gathering and Processing segment; and
- $0.5 million increase in consumable products.

General and Administrative. General and administrative expense decreased to $17.4 million in the three months ended September 30, 2011 from $18.1 million during the three months ended September 30, 2010. The change was primarily due to the following:

- $3.5 million decrease in employee related costs due to the shared services integration and subsequent reduction in employee headcount; offset by
- $2.3 million increase in related party general and administrative expenses for the services agreements with Services Co. and ETC.

Depreciation and Amortization. Depreciation and amortization expense increased to $42 million in the three months ended September 30, 2011 from $32.2 million in the three months ended September 30, 2010. This increase was the result of $7.7 million of additional depreciation and amortization expense due primarily to the completion of various organic growth projects since September 2010 and a $2.1 million increase related to our Contract Treating segment that we acquired in September 2010.

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Income from Unconsolidated Affiliates. Income from unconsolidated affiliates increased to $30.9 million for the three months ended September 30, 2011 from $21.8 million for the three months ended September 30, 2010. The schedule below summarizes the components of income from unconsolidated affiliates and our ownership interest for the three months ended September 30, 2011 and 2010, respectively:

	Three Months Ended September 30, 2011				Three Months Ended September 30, 2010			
	HPC	MEP	Lone Star	Total	HPC	MEP	Lone Star	Total
Net income	$24,282	$21,998	$30,952	$77,232	$30,366	$16,351	N/A	$46,717
Average ownership interest (1)	49.99 %	50 %	30 %	N/M	49.99 %	49.9 %	N/A	N/M
Share of unconsolidated affiliates' net income	12,138	10,985	9,285	32,408	15,180	8,159	N/A	23,339
Less: Amortization of excess fair value of unconsolidated affiliates	(1,462)	—	—	(1,462)	(1,585)	—	N/A	(1,585)
Income from unconsolidated affiliates	$10,676	$10,985	$9,285	$30,946	$13,595	$8,159	N/A	$21,754

(1) Ownership interest in MEP increased to 50% in September 2011 due to the purchase of an additional 0.1% interest.

N/A We acquired a 30% interest in Lone Star on May 2, 2011.

N/M Not meaningful.

HPC's net income decreased to $24.3 million for the three months ended September 30, 2011 from $30.4 million for the three months ended September 30, 2010, primarily due to expiration of certain contracts not renewed as well as lower volumes from one customer, whose system has been shut down since June 2011. Throughput decreased to 1,192,000 MMBtu/d for the three months ended September 30, 2011 from 1,520,000 MMBtu/d for the three months ended September 30, 2010.

MEP's net income increased to $22 million for the three months ended September 30, 2011 from $16.4 million for the three months ended September 30, 2010, primarily due to an increase in revenues despite a decrease in throughput. The increase in revenue was due to a capacity curtailment on a leased facility for most of the third quarter of 2010 while in 2011 there were no such issues.

The following table presents operational data for each of our unconsolidated affiliates for the three months ended September 30, 2011 and 2010:

		Three Months Ended September 30,	
	Operational data	2011	2010
HPC	Throughput (MMBtu/d)	1,192,203	1,519,716
MEP	Throughput (MMBtu/d)	1,320,480	1,365,674
Lone Star	West Texas Pipeline – Total Volumes (Bbls/d)	133,149	N/A
	NGL Fractionation Throughput (Bbls/d)	13,833	N/A

N/A We acquired a 30% interest in Lone Star on May 2, 2011.

Other Income and Deductions, Net. Other income and deductions, net increased to a net gain of $15.1 million in the three months ended September 30, 2011 from a net gain of $7.5 million in the three months ended September 30, 2010, primarily due to the non-cash mark-to-market adjustment on the embedded derivatives related to the Series A Preferred Units.

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Nine Months Ended September 30, 2011 vs. Combined Nine Months Ended September 30, 2010

	Successor		Predecessor			
	Nine Months Ended September 30, 2011	Period from Acquisition (May 26, 2010) to September 30, 2010	Period from January 1, 2010 to May 25, 2010	Combined Nine Months Ended September 30, 2010	Change	Percent
Total revenues	$1,064,017	$ 393,868	$ 505,050	$ 898,918	$165,099	18 %
Cost of sales	755,262	283,206	357,778	640,984	(114,278)	18
Total segment margin (1)	308,755	110,662	147,272	257,934	50,821	20
Operation and maintenance	105,506	44,708	47,842	92,550	(12,956)	14
General and administrative	54,010	25,176	37,212	62,388	8,378	13
Loss on asset sales, net	50	210	303	513	463	90
Depreciation and amortization	122,695	42,750	41,784	84,534	(38,161)	45
Operating income (loss)	26,494	(2,182)	20,131	17,949	8,545	48
Income from unconsolidated affiliates	86,921	29,875	15,872	45,747	41,174	90
Interest expense, net	(73,548)	(28,460)	(36,321)	(64,781)	(8,767)	14
Other income and deductions, net	20,105	4,003	(3,897)	106	19,999	N/M
Income (loss) from continuing operations before income taxes	59,972	3,236	(4,215)	(979)	60,951	N/M
Income tax (benefit) expense	(19)	695	404	1,099	1,118	102
Net income (loss) from continuing operations	59,991	2,541	(4,619)	(2,078)	62,069	N/M
Discontinued operations	—	410	(327)	83	(83)	100
Net income (loss)	59,991	2,951	(4,946)	(1,995)	61,986	N/M
Net income attributable to noncontrolling interest	(1,073)	(87)	(406)	(493)	(580)	118
Net income (loss) attributable to Regency Energy Partners LP	$58,918	$ 2,864	$ (5,352)	$ (2,488)	$61,406	N/M
Gathering and processing segment margin	$169,011	$ 57,096	$ 85,997	$ 143,093	$25,918	18
Non-cash loss from commodity derivatives	606	16,217	7,150	23,367	(22,761)	97
Adjusted gathering and processing segment margin	169,617	73,313	93,147	166,460	3,157	2
Contract compression segment margin (2) (3)	116,370	50,997	62,356	113,353	3,017	3
Contract treating segment margin (2)	21,594	2,730	—	2,730	18,864	691
Corporate and others segment margin	14,582	7,706	8,045	15,751	(1,169)	7
Intersegment eliminations (3)	(12,802)	(7,867)	(9,126)	(16,993)	4,191	25

Adjusted total segment margin	$309,361	$ 126,879	$ 154,422	$ 281,301	$28,060	10	%

(1) For a reconciliation of segment margin to the most directly comparable financial measure calculated and presented in accordance with GAAP, see the reconciliation provided above.
(2) Segment margin differs from previously disclosed amounts due to the reorganization of our operating segments.
(3) Contract Compression segment margin includes intersegment revenues of $12.8 million for the nine months ended September 30, 2011 and $17 million for the combined nine months ended September 30, 2010. These intersegment revenues were eliminated upon consolidation.
N/M Not meaningful.

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Net Income (Loss) Attributable to Regency Energy Partners LP. Our net income increased to $58.9 million in the nine months ended September 30, 2011 from a net loss of $2.5 million in the combined nine months ended September 30, 2010. The major components of this change were as follows:

- $50.8 million increase in total segment margin primarily due to a $25.9 million increase in Gathering and Processing segment margin related to additional volumes in south Texas and an $18.9 million increase related to the Contract Treating segment which was acquired in September 2010;
- $41.2 million increase in income from unconsolidated affiliates from the acquisition of a 30% interest in Lone Star in May 2011 and the purchase of a 49.9% interest of MEP in May 2010;
- $20 million increase in other income and deductions, net which primarily relate to the mark-to-market gain associated with the embedded derivatives related to the Series A Preferred Units;
- $8.4 million decrease in general and administrative expense primarily from a decrease in employee expenses due to the shared services integration and resulting decrease in headcount offset by an increase in the shared services billings; offset by
- $38.2 million increase in depreciation and amortization expense primarily related to the completion of various organic growth projects since June 2010, the additional depreciation and amortization expense from the acquisition of Zephyr in September 2010 and the increase of property, plant and equipment and intangible assets resulting from the fair value adjustments upon the change of control resulting from the acquisition of our General Partner in May 2010; and
- $13 million increase in operation and maintenance expense primarily due to an increase in short-term incentive accruals, an increase related to the Contract Treating segment which was purchased in September 2010, and an increase in consumable products.

Adjusted Total Segment Margin. Adjusted total segment margin increased to $309.4 million in the nine months ended September 30, 2011 from $281.3 million in the combined nine months ended September 30, 2010. The major components of this increase were as follows:

- Adjusted Gathering and Processing segment margin increased to $169.6 million during the nine months ended September 30, 2011 from $166.5 million for the combined nine months ended September 30, 2010 primarily due to volume growth in the Eagle Ford Shale and west Texas. Total Gathering and Processing throughput increased to 1,132,000 MMBtu/d during the nine months ended September 30, 2011 from 986,000 MMBtu/d during the nine months ended September 30, 2010. Total NGL gross production increased to 30,000 Bbls/d during the nine months ended September 30, 2011 from 25,000 Bbls/d during the nine months ended September 30, 2010;
- Contract Compression segment margin increased to $116.4 million in the nine months ended September 30, 2011 from $113.4 million in the combined nine months ended September 30, 2010. The increase was primarily attributable to increased revenue generating horsepower provided to external customers. As of September 30, 2011, our Contract Compression segment's total revenue generating horsepower was 769,000 compared to 754,000 as of September 30, 2010;
- Contract Treating segment margin was $21.6 million for the nine months ended September 30, 2011 from $2.7 million in the combined nine months ended September 30, 2010. We acquired the Contract Treating segment in September 2010. Revenue generating GPM as of September 30, 2011 and September 30, 2010 was 3,468 and 3,093, respectively; and
- Intersegment eliminations decreased to $12.8 million in the nine months ended September 30, 2011 from $17 million in the nine months ended June 30, 2010. The decrease was primarily due to a decrease in transactions between the Gathering and Processing and the Contract Compression segments as a result of the transfer of certain compression units from the Contract Compression segment to the Gathering and Processing segment in the second quarter of 2011.

Operation and Maintenance. Operation and maintenance expense increased to $105.5 million in the nine months ended September 30, 2011 from $92.6 million during the combined nine months ended September 30, 2010. The increase was primarily due to the following:

- $6.4 million increase in labor costs primarily due to an increase in short-term incentive accruals;
- $2 million increase in expense related to our Contract Treating segment that we acquired in September 2010; and
- $1.1 million increase in consumable products.

General and Administrative. General and administrative expense decreased to $54 million in the nine months ended September 30, 2011 from $62.4 million during the combined nine months ended September 30, 2010. The decrease was primarily due to the following:

- $6.7 million decrease in employee expenses due to the shared services integration and resulting reduction in headcount;

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- the absence of $9.7 million related to the vesting of outstanding LTIP grants upon the acquisition of our General Partner by ETE in May 2010; offset by
- $9 million increase in related party general and administrative expenses for the services agreements with Services Co. and ETC.

Depreciation and Amortization. Depreciation and amortization expense increased to $122.7 million in the nine months ended September 30, 2011 from $84.5 million in the combined nine months ended September 30, 2010. This increase was the result of $22.4 million of additional depreciation and amortization expense due to the completion of various organic growth projects since June 2010 and $8.1 million related to our Contract Treating segment that we acquired in September 2010. In addition, $7.7 million of additional depreciation and amortization expense was recorded related to the increase of property, plant and equipment amounts resulting from the fair value adjustments upon the change in control resulting from the acquisition of our General Partner in May 2010. Had the change in control occurred on January 1, 2010, our depreciation and amortization expense for the combined nine months ended September 30, 2010 would have been $92.2 million.

Income from Unconsolidated Affiliates. Income from unconsolidated affiliates increased to $86.9 million for the nine months ended September 30, 2011 from $45.7 million for the combined nine months ended September 30, 2010. The schedule set forth below summarizes the components of income from unconsolidated affiliates and our ownership interest for the nine months ended September 30, 2011 and 2010, respectively:

	Nine Months Ended September 30, 2011				Combined Nine Months Ended September 30, 2010			
	HPC	MEP	Lone Star	Total	HPC	MEP	Lone Star	Total
Net income	$84,703	$62,684	$58,910	$206,297	$74,640	$24,419	N/A	$99,059
Average ownership interest (1)	49.99 %	50 %	30 %	N/M	49.99 %	49.9 %	N/A	N/M
Share of unconsolidated affiliates’ net income	42,343	31,290	17,673	91,306	35,511	12,185	N/A	47,696
Less: Amortization of excess fair value of unconsolidated affiliates	(4,385)	—	—	(4,385)	(1,949)	—	N/A	(1,949)
Income from unconsolidated affiliates	$37,958	$31,290	$17,673	$86,921	$33,562	$12,185	N/A	$45,747

(1) Ownership interest in MEP increased to 50% in September 2011 due to the purchase of an additional 0.1% interest.

N/A We acquired a 30% interest in Lone Star on May 2, 2011.

N/M Not meaningful.

HPC’s net income increased to $84.7 million for the nine months ended September 30, 2011 from $74.6 million for the combined nine months ended September 30, 2010, and was primarily due to increased throughput from 1,188,000 MMBtu/d to 1,411,000 MMBtu/d.

We acquired a 49.9% interest in MEP in May 2010; therefore, the net income in the prior period only reflected the activity from May 26, 2010 to September 30, 2010.

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The following table presents operational data for each of our unconsolidated affiliates for the nine months ended September 30, 2011 and 2010:

		Nine Months Ended September 30,			
	Operational data	2011		2010	
HPC	Throughput (MMBtu/d)	1,411,201		1,188,345	
MEP	Throughput (MMBtu/d)	1,245,904		1,346,462	(1)
Lone Star	West Texas Pipeline – Total Volumes (Bbls/d)	131,147	(2)	N/A	
	NGL Fractionation Throughput (Bbls/d)	14,912	(2)	N/A	

(1) 2010 throughput only represents the period from May 26, 2010 (initial acquisition date) to September 30, 2010.
(2) Lone Star's operational volumes represent the period from May 2, 2011 (initial acquisition date) to September 30, 2011.
N/A We acquired a 30% interest in Lone Star on May 2, 2011.

Other Income and Deductions, Net. Other income and deductions, net increased to a net gain of $20.1 million in the nine months ended September 30, 2011 from a net gain of $0.1 million in the combined nine months ended September 30, 2010, primarily due to the non-cash mark-to-market adjustment on the embedded derivatives related to the Series A Preferred Units.

RECENTLY ISSUED ACCOUTING STANDARDS

In September 2011, the FASB issued Accounting Standards Update No. 2011-08, Intangibles - Goodwill and Other (Topic 350): Testing Goodwill for Impairment ("ASU 2011-08"), which simplifies how entities test goodwill for impairment. ASU 2011-08 gives entities the option, under certain circumstances, to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether further impairment testing is necessary. ASU 2011-08 is effective for fiscal years beginning after December 15, 2011, and early adoption is permitted. We are currently evaluating early adoption of ASU 2011-08; however, we do not expect adoption of this standard will materially impact our financial position or results of operations.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

In addition to the information set forth in this report, further information regarding our critical accounting policies and estimates is included in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2010.

See Item 1, Note 1 - Organization and Summary of Significant Accounting Policies of this report for the description of our push-down accounting in connection with the change of control resulting from the acquisition of our General Partner in May 2010.

OTHER MATTERS

Information regarding our commitments and contingencies is included in Note 6 – Commitments and Contingencies to the condensed consolidated financial statements included in Item 1 of this report.

IRS Audits. A closing conference concluding the IRS examination of the Partnership's 2007 and 2008 tax returns was held on April 19, 2011. The IRS proposed various adjustments to the Partnership's tax returns which the Partnership anticipates appealing. Until this matter is fully resolved, it is not known whether any amounts ultimately recorded would be material, or how such adjustments would affect unitholders.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

We expect our sources of liquidity to include:

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

We expect our base growth capital expenditures to be $373 million in 2011, which includes $200 million for the Gathering and

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Processing segment, mostly in south Texas, $95 million for the Contract Compression segment, $65 million for the Joint Ventures segment, $9 million for the Contract Treating segment, and $4 million for the Corporate and Others segment. In addition, we expect our maintenance capital expenditures to be $17 million in 2011.

We do not anticipate contributing any amounts to HPC in 2011 to fund its growth capital expenditures as these amounts are expected to be funded under its revolving credit facility.

In 2012, we expect to invest between $630 and $680 million in growth capital expenditures, of which $290 million is expected to be invested in organic growth projects in the Gathering and Processing segment, including a portion for the south Texas gathering system expansion; between $250 and $300 million is expected to be invested in our portion of growth capital expenditures for Lone Star; $70 million is expected to be invested in the fabrication of new compressor packages for the Contract Compression segment; $15 million is expected to be invested in the fabrication of new treating plants for the Contract Treating segment; and $5 million is expected to be invested in the Corporate and Others segment.

We may revise the timing of these expenditures as necessary to adapt to economic conditions. We expect to fund our growth capital expenditures with borrowings under our revolving credit facility and a combination of debt and equity issuances.

Working Capital. Working capital is the amount by which current assets exceed current liabilities and is a measure of our ability to pay our obligations as they become due. When we incur growth capital expenditures, we may experience working capital deficits as we fund construction expenditures out of working capital until we permanently finance them. Our working capital is also influenced by current derivative assets and liabilities due to fair value changes in our derivative positions being reflected on our balance sheet. These derivative assets and liabilities represent our expectations for the settlement of derivative rights and obligations over the next 12 months, based on quoted future commodity prices and interest rates, and should be viewed differently from trade accounts receivable and accounts payable, which settle over a shorter span of time. When our derivative positions are settled, we expect an offsetting physical transaction, and, as a result, we do not expect derivative assets and liabilities to affect our ability to pay expenditures and obligations as they come due. Our Contract Compression and Contract Treating segments record deferred revenues as a current liability, which represents billings in advance of services performed. As the revenues associated with the deferred revenues are earned, the liability is reduced.

Our working capital deficit increased to $52.7 million at September 30, 2011 from $35.1 million at December 31, 2010. This deficit increase was primarily due to a $12.5 million decrease in net trade receivables and payables due to the timing of cash receipts and disbursements, as well as a $5.9 million decrease in net related party receivables and payables primarily resulting from transactions with affiliates of ETE.

Cash Flows from Operating Activities. Net cash flows provided by operating activities increased to $204.4 million in the nine months ended September 30, 2011 from $127.9 million in the combined nine months ended September 30, 2010. The increase in cash flows from operating activities was primarily due to an increase in net income and additional distributions from unconsolidated affiliates primarily due to the acquisition of our interest in MEP in May 2010 and the acquisition of our interest in Lone Star in May 2011.

Cash Flows used in Investing Activities. Net cash flows used in investing activities increased to $857.8 million in the nine months ended September 30, 2011 from $333.5 million in the combined nine months ended September 30, 2010, primarily related to capital expenditures for growth projects and the May 2011 acquisition of a 30% interest in Lone Star.

Growth Capital Expenditures. Growth capital expenditures are capital expenditures made to acquire additional assets to increase our business, to expand and upgrade existing systems and facilities or to construct or acquire systems or facilities. In the nine months ended September 30, 2011, we incurred $258 million of growth capital expenditures. Growth capital expenditures for the nine months ended September 30, 2011 are primarily related to $172 million for organic growth projects for our Gathering and Processing segment, $68 million for the fabrication of new compressor packages for our Contract Compression segment, $10 million for growth projects for our Joint Ventures segment, $5 million for the fabrication of new treating plants for our Contract Treating segment, and $3 million for vehicle fleet purchases in our Corporate and Others segment.

Maintenance Capital Expenditures. Maintenance capital expenditures are capital expenditures made to replace partially or fully depreciated assets or to maintain the existing operating capacity of our assets and extend their useful lives. In the nine months ended September 30, 2011, we incurred $14 million of maintenance capital expenditures.
Cash Flows from Financing Activities. Net cash flows provided by financing activities increased to $649.2 million in the nine months ended September 30, 2011 from $199.8 million during the same combined period in 2010. The increase is primarily due to a $500 million senior note offering in May 2011 and an equity issuance resulting in net proceeds of $203.9 million in May 2011, partially to fund the acquisition of our 30% interest in Lone Star and our growth capital expenditures. These cash flows were partially offset by increased Partnership distributions.

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Capital Resources. In May 2011, we issued 8,500,001 common units representing limited partnership interests resulting in net proceeds of $203.9 million, to partially fund our capital contribution to Lone Star. These units were issued in a private placement conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933, as amended, under section 4(2) thereof. These units were subsequently registered with the SEC.

In October 2011, we issued 11,500,000 common units representing limited partnership interests in a public offering at a price of $20.92 per common unit, resulting in net proceeds of $231.9 million which were used to repay outstanding borrowings under the revolving credit facility.

Amendment of Revolving Credit Facility. In May 2011, we amended our Fifth Amended and Restated Credit Agreement to permit the acquisition of equity interest in Lone Star and to allow for additional investments in Lone Star of up to $150 million.

Senior Notes Offering. During the second quarter of 2011, we issued $500 million in senior notes that mature on July 15, 2021. The senior notes bear interest at 6.5% payable semi-annually in arrears on January 15 and July 15, commencing January 15, 2012. The proceeds were used to repay borrowings outstanding under our revolving credit facility.

Cash Distributions from Unconsolidated Affiliates. During the nine months ended September 30, 2011, we received cash distributions of $131.7 million from our investments in unconsolidated affiliates.

Item 3. Quantitative and Qualitative Disclosure about Market Risk

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

Commodity Price Risk. We are a net seller of NGLs, condensate and natural gas as a result of our gathering and processing operations. The prices of these commodities are impacted by changes in supply and demand as well as market forces. Our profitability and cash flow are affected by the inherent volatility of these commodities, which could adversely affect our cash available for distribution and our ability to make distributions to our unitholders. We manage this commodity price exposure through an integrated strategy that includes management of our contract portfolio, matching sales prices of commodities with purchases, optimization of our portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, we may not be able to match pricing terms or to cover our risk to price exposure with financial hedges, and we may be exposed to commodity price risk. Speculative positions with derivative contracts are prohibited under our risk management policy.

We execute natural gas, NGLs and WTI trades on a periodic basis to hedge our anticipated equity exposure. Our swap contracts settle against condensate, ethane, propane, butane, natural gas, and natural gasoline market prices. We continually monitor our hedging and contract portfolio and expect to continue to adjust our hedge positions as conditions warrant.

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The following table sets forth certain information regarding our hedges for natural gas, NGLs and WTI outstanding at September 30, 2011. The relevant index price that we pay for NGLs is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas, as reported by the Oil Price Information Service (OPIS). The relevant index price for natural gas is NYMEX on the pricing dates as defined by the swap contracts. The relevant index for WTI is the monthly average of the daily price of WTI as reported by the NYMEX. The fair value of our outstanding trades is determined using a discounted cash flow model based on third-party prices and readily available market information.

Period	Underlying	Notional Volume/ Amount		We Pay	We Receive Weighted Average Price		Fair Value Asset/ (Liability)	Effect of Hypothetical Change in Index*
							(in thousands)	
October 2011-September 2012	Ethane	439	(MBbls)	Index	0.47	($/gallon)	$(4,434)	$1,304
October 2011-March 2013	Propane	362	(MBbls)	Index	1.10	($/gallon)	(4,029)	2,078
October 2011-March 2013	Normal Butane	217	(MBbls)	Index	1.49	($/gallon)	(1,995)	1,560
October 2011-March 2013	Natural Gasoline	115	(MBbls)	Index	1.95	($/gallon)	(687)	1,012
October 2011-March 2014	West Texas Intermediate Crude	417	(MBbls)	Index	93.09	($/Bbl)	4,817	3,387
October 2011-December 2012	Natural gas	2,934,000	(MMBtu)	Index	5.10	($/MMBtu)	2,806	1,216
October 2011-April 2012	Interest Rate	$250,000,000		1.325%	Three-month LIBOR		(1,078)	1,250
					Total Fair Value		$(4,600)	

* Price risk sensitivities were calculated by assuming a theoretical 10% change, increase or decrease, in prices regardless of the term or the historical relationships between the contractual price of the instrument and the underlying commodity price. Interest rate sensitivity assumes a 100 basis point increase or decrease in the LIBOR yield curve. These price sensitivity results are presented in absolute terms.

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 Principal Financial Officer of our General Partner, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rule 13a–15(e) and 15d–15(e) of the Exchange Act). Based on that evaluation, management, including the Chief Executive Officer and Principal Financial Officer of our General Partner, concluded that our disclosure controls and procedures were effective as of September 30, 2011 to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is properly recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

Internal control over financial reporting. There have been no changes in our internal controls over financial reporting (as defined in Rule 13(a)–15(f) or Rule 15d–15(f) of the Exchange Act) during the three months ended September 30, 2011 that have materially affected, or are reasonably likely to materially affect, 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 6, 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

For information regarding risk, uncertainties and assumptions, see Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2010. Except as disclosed below, there are no material changes from the risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2010 and our Quarterly Reports on Forms 10-Q for the quarters ended March 31, 2011 and June 30, 2011.

RISKS RELATED TO OUR BUSINESS

We own an equity interest in HPC, MEP and Lone Star, but we do not exercise control over any of these entities.

We own a 49.99% general partner interest in HPC, and we have the right to appoint two members of the four-member management committee. We also have the right to vote the 0.01% general partner interest retained by EFS Haynesville, LLC, an affiliate of General Electric Company. Alinda Gas Pipeline I, L.P. and Alinda Gas Pipeline II, L.P. own the remaining 50% general partner interest in HPC and have the right to appoint the other two members of the management committee. Each member of the management committee has a vote equal to the sharing ratio of the partner that appointed such member. Accordingly, we do not exercise control over HPC. HPC's partnership agreement requires that the following actions, among other things, be approved by at least 75% of the members of the management committee: a merger or consolidation of HPC; the sale of all or substantially all of the assets of HPC; a determination to raise additional capital; determining the amount of available cash; causing HPC to terminate the master services agreement with us; approval of any budget; and entry into material contracts.

We own a 50% membership interest in MEP, and we have the right to appoint one member to the two-member board of directors. An affiliate of Kinder Morgan Energy Partners, L.P. owns a 50% membership interest in MEP and has the right to appoint the other member of the board of directors, appoint the officers of MEP and to manage the business operations of MEP. Accordingly, we do not exercise control over MEP. MEP's limited liability company agreement provides that 65% of the membership interests constitute a quorum. Most matters require a majority vote, but the following actions, among other things, require the approval of at least 80% of the membership interests: the sale of any assets outside the ordinary course of business or with a fair market value in excess of $5,000,000; a merger, consolidation or liquidation; modifying or terminating any agreement with a member; issuing, selling or repurchasing membership interests; incurring or refinancing indebtedness in excess of $25,000,000; and filing or settling any litigation or arbitration that involves claims or settlements in excess of $5,000,000.

We own a 30% membership interest in Lone Star, and we have the right to appoint one member to the two-member board of directors. ETP owns a 70% membership interest in Lone Star and has the right to appoint the other member to the board of directors. Under the limited liability company agreement of Lone Star, all decisions regarding the management of the business and affairs of Lone Star are made by ETP, but the following actions, among other things, require the unanimous consent of the board of directors: entering into contracts with a term longer than three years with revenues or expenses greater than $10,000,000; filing or settling any litigation or arbitration that involves claims or settlements in excess of $1,000,000; entering into, modifying or terminating any agreement with a member; the purchase or sale of any assets with a fair market value in excess of $5,000,000 in one or more related transactions in any calendar year; a merger, consolidation or liquidation; issuing, selling or repurchasing membership interests; or incurring or refinancing any indebtedness of Lone Star.

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

None.

Item 3. Defaults upon Senior Securities

None.

Item 4.
[Removed and Reserved]

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Item 5. Other Information
None.
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 Principal Financial Officer
Exhibit 32.1 –	Section 1350 Certifications of Chief Executive Officer
Exhibit 32.2 –	Section 1350 Certifications of Principal Financial Officer
Exhibit 101.INS –	XBRL Instance Document
Exhibit 101.SCH –	XBRL Taxonomy Extension Schema
Exhibit 101.CAL –	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.DEF –	XBRL Taxonomy Extension Definition Linkbase
Exhibit 101.LAB –	XBRL Taxonomy Extension Label Linkbase
Exhibit 101.PRE –	XBRL Taxonomy Extension Presentation Linkbase

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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
Date: November 7, 2011	/S/ A. TROY STURROCK A. Troy Sturrock Vice President, Controller and Principal Accounting Officer (Duly Authorized Officer)