Regency Energy Partners LP
Form 10-Q
August 08, 2013
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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 June 30, 2013
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 (§232.405 of this chapter) 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 209,876,254 common units and 6,274,483 Class F common units outstanding as of August 2, 2013.

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Introductory Statement

References in this report to the "Partnership," "we," "our," "us" and similar terms refer to Regency Energy Partners LP 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 (Loss)
ARO	Asset Retirement Obligation
Bbls	Barrels
bps	Basis points
BTU	A unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit
ELG	Edwards Lime Gathering LLC and its wholly-owned subsidiaries, ELG Oil LLC and ELG Utility LLC
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.
ETP	Energy Transfer Partners, L.P.
Finance Corp.	Regency Energy Finance Corp., a wholly-owned subsidiary of the Partnership
GAAP	Accounting principles generally accepted in the United States of America
General Partner	Regency GP LP, the general partner of the Partnership, or Regency GP LLC, the general partner of Regency GP LP, which effectively manages the business and affairs of the Partnership through Regency Employees Management LLC
Grey Ranch	A 50% joint venture between SUGS and a subsidiary of Sandridge Energy
Gulf States	Gulf States Transmission LLC, a wholly-owned subsidiary of the Partnership
Holdco	ETP Holdco Corporation
HPC	RIGS Haynesville Partnership Co., a general partnership, and its wholly-owned subsidiary, Regency Intrastate Gas LP
IDRs	Incentive Distribution Rights
LIBOR	London Interbank Offered Rate
Lone Star	Lone Star NGL LLC
LTIP	Long-Term Incentive Plan
MBbls	One thousand barrels
MEP	Midcontinent Express Pipeline LLC
MMBtu	One million BTUs
MMcf	One million cubic feet
NGLs	Natural gas liquids, including ethane, propane, normal butane, iso butane and natural gasoline
NYMEX	New York Mercantile Exchange
NMED	New Mexico Environmental Department
Partnership	Regency Energy Partners LP
PEPL Holdings	PEPL Holdings, LLC, a wholly-owned subsidiary of Southern Union
Ranch JV	Ranch Westex JV LLC
Regency Western	Regency Western G&P LLC, an indirectly wholly owned subsidiary of the Partnership
RGS	Regency Gas Services LP, a wholly-owned subsidiary of the Partnership
RIGS	Regency Intrastate Gas System
SEC	Securities and Exchange Commission
Senior Notes	

	The collective of 2016 Notes, 2018 Notes, 2021 Notes, 2023 5.5% Notes and 2023 4.5% Notes
Series A Preferred Units	Series A convertible redeemable preferred units
Services Co.	ETE Services Company, LLC
Southern Union	Southern Union Company
SUGS	Southern Union Gathering Company LLC
TCEQ	Texas Commission on Environmental Quality
WTI	West Texas Intermediate Crude

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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 we 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, condensate 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 our contract services business;
- 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 and NGL 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, 2012 Annual Report on Form 10-K and in 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
Regency Energy Partners LP
Condensed Consolidated Balance Sheets
(in millions)
(unaudited)

	June 30, 2013	December 31, 2012
ASSETS		
Current Assets:		
Cash and cash equivalents	$17	$53
Trade accounts receivable, net	99	115
Accrued revenues	141	107
Related party receivables	20	8
Derivative assets	10	4
Other current assets	58	53
Total current assets	345	340
Property, plant and equipment:		
Property, plant and equipment	4,587	4,086
Less accumulated depreciation	(514)	(400)
Property, plant and equipment, net	4,073	3,686
Other Assets:		
Investment in unconsolidated affiliates	2,224	2,214
Long-term derivative assets	3	1
Other, net of accumulated amortization of debt issuance costs of $20 and $17	52	42
Total other assets	2,279	2,257
Intangible assets, net of accumulated amortization of $91 and $74	696	712
Goodwill	1,128	1,128
TOTAL ASSETS	$8,521	$8,123
LIABILITIES AND PARTNERS’ CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Drafts payable	$17	$10
Trade accounts payable	140	122
Accrued cost of gas and liquids	135	133
Related party payables	43	95
Deferred revenues	16	17
Derivative liabilities	1	6
Other current liabilities	57	106
Total current liabilities	409	489
Long-term derivative liabilities	47	25
Other long-term liabilities	38	39
Long-term debt, net	2,935	2,157
Commitments and contingencies		
Series A Preferred Units, redemption amount of $86 and $85	73	73
Partners’ capital and noncontrolling interest:		
Common units	3,988	3,207
Class F common units	143	—
General partner interest	798	326

Predecessor equity	—	1,733
Accumulated other comprehensive loss	—	(3)
Total partners' capital	4,929	5,263
Noncontrolling interest	90	77
Total partners' capital and noncontrolling interest	5,019	5,340
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$8,521	$8,123

See accompanying notes to condensed consolidated financial statements

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	2013		2012		2013		2012	
REVENUES								
Gas sales, including related party amounts of $26, $9, $34 and $15	$220		$108		$387		$189	
NGL sales, including related party amounts of $11, $1, $12 and $26	245		265		480		442	
Gathering, transportation and other fees, including related party amounts of $6, $7, $14 and $14	131		95		258		196	
Net realized and unrealized loss from derivatives	14		21		11		19	
Other, including related party amounts of $–, $–, $– and $1	29		22		43		40	
Total revenues	639		511		1,179		886	
OPERATING COSTS AND EXPENSES								
Cost of sales, including related party amounts of $23, $8, $27 and $16	445		336		832		590	
Operation and maintenance, including related party amounts of $–, $3, $– and $18	73		57		142		98	
General and administrative, including related party amounts of $3, $4, $7 and $9	18		25		51		57	
Loss on asset sales, net	1		2		2		2	
Depreciation and amortization	68		69		133		122	
Total operating costs and expenses	605		489		1,160		869	
OPERATING INCOME	34		22		19		17	
Income from unconsolidated affiliates	31		34		66		66	
Interest expense, net	(41	)	(28	)	(78	)	(57	)
Loss on debt refinancing, net	(7	)	(8	)	(7	)	(8	)
Other income and deductions, net	(7	)	8		(21	)	25	
INCOME (LOSS) BEFORE INCOME TAXES	10		28		(21	)	43	
Income tax benefit	(1	)	—		(3	)	—	
NET INCOME (LOSS)	$11		$28		$(18	)	$43	
Net income attributable to noncontrolling interest	(1	)	(1	)	(1	)	(1	)
NET INCOME (LOSS) ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$10		$27		$(19	)	$42	
Amounts attributable to Series A Preferred Units	2		2		4		5	
General partner’s interest, including IDRs	3		3		5		5	
Beneficial conversion feature for Class F Units	1		—		1		—	
Pre-acquisition income from SUGS allocated to general partner	(9	)	(1	)	(33	)	(15	)
Limited partners’ interest in net income (loss)	$13		$23		$4		$47	
Basic and diluted net income per common unit:								
Amount allocated to common units	$13		$23		$4		$47	
Weighted average number of common units outstanding	193,065,183		170,107,060		182,070,077		164,398,548	
Basic income per common unit	$0.07		$0.14		$0.02		$0.29	

Diluted income per common unit	$0.07	$0.10	$0.02	$0.26
Distributions per common unit	$0.465	$0.46	$0.925	$0.92
Amount allocated to Class F units due to beneficial conversion feature	$1	$—	$1	$—
Total number of Class F units outstanding	6,274,483	—	6,274,483	—
Income per Class F unit due to beneficial conversion feature	$0.18	$—	$0.18	$—

See accompanying notes to condensed consolidated financial statements

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net income (loss)	$11	$28	$(18)	$43
Other comprehensive income:				
Net cash flow hedge amounts reclassified to earnings	—	(4)	—	—
Change in fair value of cash flow hedges	—	10	—	11
Total other comprehensive income	—	6	—	11
Comprehensive income (loss)	11	34	(18)	54
Comprehensive income attributable to noncontrolling interest	1	1	1	1
Comprehensive income (loss) attributable to Regency Energy Partners LP	$10	$33	$(19)	$53

See accompanying notes to condensed consolidated financial statements

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

	Six Months Ended June 30, 2013	2012
OPERATING ACTIVITIES:		
Net (loss) income	$(18)	$43
Reconciliation of net income to net cash flows provided by operating activities:		
Depreciation and amortization, including debt issuance cost amortization and bond premium write-off and amortization	137	125
Income from unconsolidated affiliates	(66)	(66)
Derivative valuation changes	17	(18)
Loss on asset sales, net	2	2
Unit-based compensation expenses	3	2
Cash flow changes in current assets and liabilities:		
Trade accounts receivable, accrued revenues and related party receivables	(41)	29
Other current assets and other current liabilities	(51)	3
Trade accounts payable, accrued cost of gas and liquids, related party payables and deferred revenues	10	(69)
Distributions of earnings received from unconsolidated affiliates	71	63
Cash flow changes in other assets and liabilities	131	(12)
Net cash flows provided by operating activities	195	102
INVESTING ACTIVITIES:		
Capital expenditures	(472)	(233)
Capital contributions to unconsolidated affiliates	(72)	(170)
Distributions in excess of earnings of unconsolidated affiliates	37	23
Acquisitions, net of cash received	(463)	—
Proceeds from asset sales	12	21
Net cash flows used in investing activities	(958)	(359)
FINANCING ACTIVITIES:		
Net borrowings under revolving credit facility	343	183
Proceeds from issuance of senior notes	600	—
Redemption of senior notes	(163)	(88)
Debt issuance costs	(17)	(1)
Drafts payable	7	—
Partner distributions	(179)	(158)
Common unit offering, net of issuance costs	128	297
Distributions to Series A Preferred Units	(4)	(4)
Contributions from noncontrolling interest	12	10
Contributions from previous parent	—	33
Net cash flows provided by financing activities	727	272
Net change in cash and cash equivalents	(36)	15
Cash and cash equivalents at beginning of period	53	1
Cash and cash equivalents at end of period	$17	$16
Supplemental cash flow information:		
Accrued capital expenditures	$133	$31
Accrued capital contribution to unconsolidated affiliate	$22	$28

Issuance of Class F and common units in connection with SUGS acquisition	$1,223	$—

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 millions)
(unaudited)

	Regency Energy Partners LP						
	Common Units	Class F Common Units	General Partner Interest	Predecessor Equity	AOCI	Noncontrolling Interest	Total
Balance - December 31, 2012	$3,207	$—	$326	$ 1,733	$(3)	$ 77	$5,340
Contribution of net investment to the Partnership	—	—	1,927	(1,930)	3	—	—
Issuance of common units in connection with the SUGS Acquisition, net of costs	819	—	(819)	—	—	—	—
Issuance of Class F common units in connection with the SUGS Acquisition, net of costs	—	142	(142)	—	—	—	—
Contribution of assets between entities under common control below historical cost	—	—	(492)	230	—	—	(262)
Issuance of common units under equity distribution program, net of costs	128	—	—	—	—	—	128
Unit-based compensation expenses	3	—	—	—	—	—	3
Partner distributions	(172)	—	(7)	—	—	—	(179)
Distributions on unvested unit awards	(1)	—	—	—	—	—	(1)
Contribution from noncontrolling interest	—	—	—	—	—	12	12
Net income (loss)	8	1	5	(33)	—	1	(18)
Distributions to Series A convertible redeemable preferred units	(4)	—	—	—	—	—	(4)
Balance - June 30, 2013	$3,988	$143	$798	$ —	$—	$ 90	$5,019

See accompanying notes to condensed consolidated financial statements

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Regency Energy Partners LP
Notes to Condensed Consolidated Financial Statements
(Tabular dollar amounts, except per unit data, are in millions)
(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"), a Delaware limited partnership. The Partnership and its subsidiaries are engaged in the business of gathering and processing, compression, treating and transportation of natural gas and the transportation, fractionation and storage of 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.

SUGS Acquisition. On April 30, 2013, the Partnership and Regency Western acquired SUGS from Southern Union, a wholly owned subsidiary of Holdco, for $1.5 billion (the "SUGS Acquisition"). The Partnership financed the acquisition by issuing to Southern Union 31,372,419 Partnership common units and 6,274,483 recently created Class F common units. The Class F common units are not entitled to participate in the Partnership's distributions for twenty-four months post-transaction closing. The remaining $600 million, less $107 million of closing adjustments, was paid in cash. In addition, ETE has agreed to forgo IDR payments on the Partnership common units issued with this transaction for twenty-four months post-transaction closing and to suspend a $10 million annual management fee paid by the Partnership for two years post-transaction close.

The common units and Class F common units related to the SUGS Acquisition were issued in a private placement conducted in accordance with the exemption from registration requirements of the Securities Act of 1933, as amended under Section 4(2) thereof. The Class F common units will convert into common units on a one-for-one basis in May 2015.

The cash portion of the SUGS Acquisition was funded from the proceeds of senior notes issued by the Partnership on April 30, 2013 in a private placement. PEPL Holdings provided a guarantee of collection with respect to the payment of the principal amounts of the senior notes issued by the Partnership.

The Partnership accounted for the acquisition in a manner similar to the pooling of interest method of accounting as it was a transaction between commonly controlled entities. Under this method of accounting, the Partnership reflected historical balance sheet data for the Partnership and SUGS instead of reflecting the fair market value of SUGS assets and liabilities from the date of acquisition forward. The Partnership retrospectively adjusted its financial statements to include the balances and operations of SUGS from March 26, 2012 (the date upon which common control began). The SUGS Acquisition does not impact historical earnings per unit as pre-acquisition earnings were allocated to predecessor equity.

The following table presents the revenues and net income for the previously separate entities and the combined amounts presented herein:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013 [(1)]	2012	2013 [(1)]	2012
Revenues:				
Partnership	$562	$312	$911	$670
SUGS	77	199	268	216
Combined	$639	$511	$1,179	$886
Net income (loss):				
Partnership	$20	$29	$15	$58
SUGS	(9)	(1)	(33)	(15)
Combined	$11	$28	$(18)	$43

(1) The SUGS Acquisition closed on April 30, 2013. Therefore, amounts attributable to SUGS only include one month and four months of activity for the three months and six months ended June 30, 2013, respectively.

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Basis of Presentation. 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, 2012. 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.

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.

Derivative Financial Instruments. Derivative transactions related to SUGS are recognized in the accompanying consolidated balance sheet at their fair value. On the date the derivative contract is entered into, SUGS designates the derivative as (i) a hedge of the fair value of a recognized asset or liability or of an unrecognized firm commitment (a fair value hedge); (ii) a hedge of a forecasted transaction or the variability of cash flows to be received or paid in conjunction with a recognized asset or liability (a cash flow hedge); or (iii) an instrument that is held for trading or non-hedging purposes (a trading or economic hedging instrument). For derivatives treated as a fair value hedge, the effective portion of changes in fair value is recorded as an adjustment to the hedged item. For derivatives treated as a cash flow hedge, the effective portion of changes in fair value is recorded in accumulated other comprehensive income (loss) in the consolidated balance sheet until the related hedge items impact earnings. Any ineffective portion of a cash flow hedge is reported in current period earnings. For derivatives treated as trading or economic hedging instruments, changes in fair value are reported in current-period earnings. Fair value is determined based upon quoted market prices and pricing models using assumptions that market participants would use. All outstanding SUGS derivative transactions as of April 30, 2013 were terminated on April 30, 2013.

Asset Retirement Obligations. Legal obligations associated with the retirement of long-lived assets are recorded at fair value at the time the obligations are incurred, if a reasonable estimate of fair value can be made. Present value techniques are used which reflect assumptions such as removal and remediation costs, inflation, and profit margins that third parties would demand to settle the amount of the future obligation. The Partnership does not include a market risk premium for unforeseeable circumstances in its fair value estimates because such a premium cannot be reliably estimated. Upon initial recognition of the liability, costs are capitalized as a part of the long-lived asset and allocated to expense over the useful life of the related asset. The liability is accreted to its present value each period with accretion being recorded to operating expense with a corresponding increase in the carrying amount of the liability. The ARO assets and liabilities as of June 30, 2013 and December 31, 2012 were $5 million.

Environmental. The Partnership's operations are subject to federal, state and local laws and rules and regulations regarding water quality, hazardous and solid waste management, air quality control and other environmental matters. These laws, rules and regulations require the Partnership to conduct its operations in a specified manner and to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with applicable environmental laws, rules and regulations may expose the Partnership to significant fines, penalties and/or interruptions in its operations. The Partnership's environmental policies and procedures are designed to achieve compliance with such applicable laws and regulations. These evolving laws and regulations and claims for damages to property, employees, other persons and the environment resulting from current or past operations may result in significant expenditures and liabilities in the future.

Income Taxes. The Partnership is generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. The Partnership is subject to the gross margins tax enacted by the state of Texas. The Partnership has two wholly-owned subsidiaries that are subject to income tax and provides for deferred income taxes using the asset and liability method. Accordingly, deferred taxes are recorded for differences between the tax and book basis that will reverse in future periods. The Partnership’s deferred tax liabilities of $20 million and

$23 million as of June 30, 2013 and December 31, 2012, respectively, relate to the difference between the book and tax basis of property, plant and equipment and intangible assets and is included in other long-term liabilities in the accompanying consolidated balance sheets. The Partnership follows the guidance for uncertainties in income taxes where a liability for an unrecognized tax benefit is recorded for a tax position that does not meet the "more likely than not" criteria. The Partnership has not recorded any uncertain tax positions meeting the more likely than not criteria as of June 30, 2013 and December 31, 2012. The Partnership recognized current federal income tax expense of less than $1 million in the six months ended June 30, 2013 and June 30, 2012. The Partnership also recognized deferred income tax benefit of $3 million for the six months ended June 30, 2013 and less than $1 million for the six months ended June 30, 2012.

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Although the SUGS operations were included in the Southern Union consolidated federal income tax return prior to the SUGS Acquisition, following their acquisition by the Partnership, their operations are now treated as a partnership. Therefore, other than one wholly-owned subsidiary, the historical operations exclude income taxes for all periods presented.

Effective with the Partnership’s acquisition of SUGS on April 30, 2013, SUGS is generally no longer subject to federal income taxes and subject only to gross margins tax in the state of Texas. Substantially all previously recorded current and deferred tax liabilities were settled with Southern Union, along with all other intercompany receivables and payables at the date of acquisition.

2. Partners’ Capital and Distributions

Predecessor equity included on the condensed consolidated statement of partners' capital and noncontrolling interest represents SUGS Member's capital prior to the acquisition date (April 30, 2013).

Beneficial Conversion Feature. The Partnership issued 6,274,483 Class F common units in connection with the SUGS Acquisition. At the commitment date (February 27, 2013), the sales price of $23.91 per unit represented a $2.19 discount from the fair value of the Partnership's common units as of April 30, 2013. Under FASB ASC 470-20, “Debt with Conversion and Other Options,” the discount represents a beneficial conversion feature that is treated as a non-cash distribution for purposes of calculating earnings per unit. The beneficial conversion feature is reflected in income per unit using the effective yield method over the period the Class F common units are outstanding, as indicated on the statement of operations in the line item entitled “beneficial conversion feature for Class F common units.” The Class F common units are convertible to common units on a one-for-one basis on May 8, 2015.

Units Activity. The change in common and Class F units during the six months ended June 30, 2013 was as follows:

	Common	Class F
Balance - December 31, 2012	170,951,457	—
Issuance of common units under LTIP, net of forfeitures and tax withholding	21,796	—
Issuance of common units under the Equity Distribution Agreement	4,887,540	—
Issuance of common units and Class F common units in connection with SUGS Acquisition	31,372,419 (1)	6,274,483 (2)
Balance - June 30, 2013	207,233,212	6,274,483

(1) ETE has agreed to forgo IDR payments on the Partnership common units issued with the SUGS Acquisition for twenty-four months post-transaction closing.

(2) The Class F common units are not entitled to participate in the Partnership’s distributions or earnings for twenty-four months post-transaction closing.

Equity Distribution Agreement. During the six months ended June 30, 2013, the Partnership received net proceeds of $128 million from units issued pursuant to an Equity Distribution Agreement with Citi, which were used for general partnership purposes. As of June 30, 2013, $56 million remains available to be issued under this agreement.

Quarterly Distributions of Available Cash. Following are distributions declared by the Partnership subsequent to December 31, 2012:

Quarter Ended	Record Date	Payment Date	Cash Distributions (per common unit)
December 31, 2012	February 7, 2013	February 14, 2013	$0.460
March 31, 2013	May 6, 2013	May 13, 2013	$0.460
June 30, 2013	August 5, 2013	August 14, 2013	$0.465

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3. Income per Common Unit

The following tables provide a reconciliation of the numerator and denominator of the basic and diluted earnings per common unit computations for the three and six months ended June 30, 2013 and 2012:

	Three Months Ended June 30,					
	2013			2012		
	Income (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
Basic income per unit						
Amounts allocated to common units	$13	193,065,183	$0.07	$23	170,107,060	$0.14
Effect of Dilutive Securities:						
Common unit options	—	24,365		—	8,474	
Phantom units *	—	331,462		—	288,644	
Series A Preferred Units	—	—		(6)	4,645,229	
Diluted income per unit	$13	193,421,010	$0.07	$17	175,049,407	$0.10

	Six Months Ended June 30,					
	2013			2012		
	Income (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
Basic income per unit						
Amounts allocated to common units	$4	182,070,077	$0.02	$47	164,398,548	$0.29
Effect of Dilutive Securities:						
Common unit options	—	19,035		—	15,033	
Phantom units *	—	303,218		—	325,129	
Series A Preferred Units	—	—		(3)	4,645,229	
Diluted income per unit	$4	182,392,330	$0.02	$44	169,383,939	$0.26

* 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 June 30, 2013	Six Months Ended June 30, 2013
Series A Preferred Units	4,672,835	4,672,835

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4. Investment in Unconsolidated Affiliates

As of June 30, 2013, the Partnership has a 49.99% general partner interest in HPC, a 50% membership interest in MEP, a 30% membership interest in Lone Star, a 33.33% membership interest in Ranch JV, and a 50% interest in Grey Ranch. The carrying value of the Partnership's investment in each of the unconsolidated affiliates as of June 30, 2013 and December 31, 2012 is as follows:

	June 30, 2013	December 31, 2012
HPC	$637	$650
MEP	564	581
Lone Star	987	948
Ranch JV	36	35
Grey Ranch	—	—
	$2,224	$2,214

The following tables summarize the Partnership's investment activities in each of the unconsolidated affiliates for the three and six months ended June 30, 2013 and 2012:

	Three Months Ended June 30, 2013				
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch
Contributions to unconsolidated affiliates	$—	$—	$22	$—	$—
Distributions from unconsolidated affiliates	(14)	(18)	(23)	—	—
Share of earnings of unconsolidated affiliates' net income	9	10	13	—	—
Amortization of excess fair value of investment	(1)	—	—	—	—

	Three Months Ended June 30, 2012				
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch
Contributions to unconsolidated affiliates	$—	$—	$95	$9	$—
Distributions from unconsolidated affiliates	(14)	(19)	(11)	—	—
Share of earnings of unconsolidated affiliates' net income	13	10	12	—	—
Amortization of excess fair value of investment	(1)	—	—	—	—

	Six Months Ended June 30, 2013				
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch
Contributions to unconsolidated affiliates	$—	$—	$49	$1	$—
Distributions from unconsolidated affiliates	(30)	(38)	(40)	—	—
Share of earnings of unconsolidated affiliates' net income	19	20	30	—	—
Amortization of excess fair value of investment	(3)	—	—	—	—

	Six Months Ended June 30, 2012				
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch
Contributions to unconsolidated affiliates	$—	$—	$175	$22	$—
Distributions from unconsolidated affiliates	(30)	(38)	(18)	—	—
Share of earnings of unconsolidated affiliates' net income	24	21	24	—	—
Amortization of excess fair value of investment	(3)	—	—	—	—

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The following tables present selected income statement data for each of the unconsolidated affiliates, on a 100% basis, for the three and six months ended June 30, 2013 and 2012:

	Three Months Ended June 30, 2013				
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch
Total revenues	$38	$63	$425	$3	$—
Operating income (loss)	19	33	45	1	(1)
Net income (loss)	18	21	44	1	(1)

	Three Months Ended June 30, 2012				
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch
Total revenues	$46	$65	$158	$—	$—
Operating income	27	34	40	—	—
Net income	26	21	41	—	—

	Six Months Ended June 30, 2013				
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch
Total revenues	$78	$128	$783	$6	$—
Operating income (loss)	39	67	101	1	(1)
Net income (loss)	38	42	99	1	(1)

	Six Months Ended June 30, 2012				
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch
Total revenues	$88	$131	$325	$—	$—
Operating income	50	68	79	—	—
Net income	49	42	79	—	—

5. 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 Committee of the General Partner is responsible for the overall management of these risks, including monitoring exposure limits. The Audit and Risk 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 supply and demand as well as 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.

The Partnership has swap contracts that settle against certain NGLs, condensate and natural gas market prices. On January 1, 2012, the Partnership de-designated its swap contracts and began accounting for these contracts using the mark-to-market method of accounting. As of December 31, 2012, SUGS had outstanding receive-fixed natural gas price swaps that were accounted for as cash flow hedges, with the effective portion of changes in their fair value recorded in accumulated other comprehensive income (loss) and reclassified into revenues in the same periods during which the forecasted natural gas sales impact earnings. As of April 30, 2013, in connection with the SUGS Acquisition, these outstanding hedges were terminated.

Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under its revolving credit facility. As of June 30, 2013, the Partnership had $535 million of outstanding borrowings exposed to variable interest rate risk.

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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 contract 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 failed to perform under existing swap contracts, the Partnership's maximum loss as of June 30, 2013 would be $13 million, which would be reduced by $1 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.

The Partnership's derivative assets and liabilities, including credit risk adjustments, as of June 30, 2013 and December 31, 2012 are detailed below:

	Assets		Liabilities	
	June 30, 2013	December 31, 2012	June 30, 2013	December 31, 2012
Derivatives designated as cash flow hedges:				
Current amounts				
Commodity contracts	$—	$—	$—	$5
Total cash flow hedging instruments	$—	$—	$—	$5
Derivatives not designated as cash flow hedges:				
Current amounts				
Commodity contracts	$10	$4	$1	$1
Long-term amounts				
Commodity contracts	3	1	—	—
Embedded derivatives in Series A Preferred Units	—	—	47	25
Total derivatives	$13	$5	$48	$31

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The Partnership's statements of operations for the three and six months ended June 30, 2013 and 2012 were impacted by derivative instruments activities as follows:

		Three Months Ended June 30,	
		2013	2012
Derivatives in cash flow hedging relationships:		Change in Value Recognized in AOCI on Derivatives (Effective Portion)	
Commodity derivatives		$—	$10
Derivatives in cash flow hedging relationships:	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	
Commodity derivatives	Revenues	$—	$6
Derivatives not designated in a hedging relationship:	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Amortized from AOCI into Income	
Commodity derivatives	Revenues	$—	$(2)
Derivatives not designated in a hedging relationship:	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Recognized in Income on Derivatives	
Commodity derivatives	Revenues	$14	$17
Embedded derivatives in Series A Preferred Units	Other income & deductions, net	(8)	8
		$6	$25

		Six Months Ended June 30,	
		2013	2012
Derivatives in cash flow hedging relationships:		Change in Value Recognized in AOCI on Derivatives (Effective Portion)	
Commodity derivatives		$—	$11
Derivatives in cash flow hedging relationships:	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	
Commodity derivatives	Revenues	$—	$6
Derivatives not designated in a hedging relationship:	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Amortized from AOCI into Income	
Commodity derivatives	Revenues	$—	$(6)
Derivatives not designated in a hedging relationship:	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Recognized in Income on Derivatives	
Commodity derivatives	Revenues	$11	$19
Embedded derivatives in Series A Preferred Units	Other income & deductions, net	(22)	8
		$(11)	$27

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6. Long-term Debt

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

	June 30, 2013	December 31, 2012
Senior notes	$2,400	$1,965
Revolving loans	535	192
Total	2,935	2,157
Less: current portion	—	—
Long-term debt	$2,935	$2,157
Availability under revolving credit facility:		
Total credit facility limit	$1,200	$1,150
Revolving loans	(535)	(192)
Letters of credit	(13)	(12)
Total available	$652	$946

Long-term debt maturities as of June 30, 2013 for each of the next five years are as follows:

Years Ending December 31,	Amount
2013 (remainder)	$—
2014	—
2015	—
2016	—
2017	—
Thereafter	2,935
Total	$2,935

Revolving Credit Facility. The weighted average interest rate on the total amounts outstanding under the Partnership's revolving credit facility was 2.20% and 2.88% as of June 30, 2013 and 2012, respectively.

In May 2013, RGS entered into the Sixth Amended and Restated Credit Agreement to increase the commitment to $1.2 billion with a $300 million uncommitted incremental facility and extended the maturity date to May 21, 2018. The material differences between the Fifth and Sixth Amended and Restated Credit Agreement include:

- A 75 bps decrease in pricing, with an additional 50 bps decrease upon the achievement of an investment grade rating.
- No limitation on the maximum amount that the loan parties may invest in joint ventures existing on the date of the credit agreement so long as the Partnership is in pro forma compliance with the financial covenants.
- The addition of a "Restricted Subsidiary" structure such that certain designated subsidiaries are not subject to the credit facility covenants and do not guarantee the obligations thereunder or pledge their assets in support thereof.
- The addition of provisions such that upon the achievement of an investment grade rating by the Partnership, the collateral package will be released; the facility will become unsecured; and the covenant package will be significantly reduced;
- An eight-quarter increase in the permitted Total Leverage Ratio; and
- After March 2015, an increase in the permitted Total Leverage Ratio for the two fiscal quarters following any $50 million or greater acquisition.

The new credit agreement and the guarantees are senior to the Partnership's and the guarantors' secured obligations, including the Series A Preferred Units, to the extent of the value of the assets securing such obligations. As of June 30, 2013, the Partnership was in compliance with all of the financial covenants contained within the new credit agreement.

The Partnership treated the May 2013 amendment of the revolving credit facility as a modification of an existing revolving credit agreement and, therefore, wrote off debt issuance costs of less than $1 million to interest expense, net in the period from January 1, 2013 to June 30, 2013. In addition, the Partnership capitalized $7 million of loan fees which will be amortized over the remaining term.

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Senior Notes. In April 2013, in conjunction with the closing of the SUGS Acquisition, the Partnership and Finance Corp. issued $600 million senior notes in a private placement (the “2023 4.5% Notes”). The 2023 4.5% Notes bear interest at 4.5% payable semi-annually in arrears on May 1 and November 1, commencing November 1, 2013 and the 2023 4.5% Notes mature on November 1, 2023.

At any time prior to August 1, 2023, we may redeem some or all of the 2023 4.5% Notes at a price equal to 100% of the principal amount plus a make-whole premium and accrued interest. On or after August 1, 2023, we may redeem some or all of the 2023 4.5% Notes at a price equal to 100% plus accrued interest.

Upon a change of control, as defined in the indenture, followed by a ratings decline within 90 days, each holder of the 2023 4.5% Notes will be entitled to require us to purchase all or a portion of its notes at a purchase price of 101% of the principal amount plus accrued interest and liquidated damages, if any. Our ability to purchase the notes upon a change of control will be limited by the terms of our debt agreements, including our revolving credit facility.

The 2023 4.5% Notes contain various covenants that limit, among other things, our ability, and the ability of certain of our subsidiaries, to:

- incur additional indebtedness;
- pay distributions on, or repurchase or redeem equity interest;
- 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 2023 4.5% Notes achieve investment grade ratings by both Moody’s and S&P and no default or event or default has occurred and is continuing, we will no longer be subject to many of the foregoing covenants.

The 2023 4.5% Notes are jointly and severally guaranteed by all of our consolidated subsidiaries, other than Finance Corp. and a minor subsidiary. PEPL Holdings provided a guarantee of collection with respect to the payment of the principal amounts of the senior notes issued by us. The senior notes and the guarantees are unsecured and rank equally with all of our and the guarantors’ existing and future unsecured obligations. The senior notes and the guarantees will be senior in right of payment to any of our and the guarantor’s future obligations that are, by their terms, expressly subordinated in right of payment to the notes and the guarantees. The senior notes and the guarantees will be effectively subordinated to our and the guarantors’ secured obligations, including our revolving credit facility, to the extent of the value of the assets securing such obligations.

In June 2013, the Partnership redeemed all of the $163 million outstanding 9.375% Senior Notes due 2016 for $178 million cash, inclusive of accrued and unpaid interest of $7 million and other fees and expenses.

At June 30, 2013, the Partnership was in compliance with all covenants.

Finance Corp. has no operations and will not have revenues other than as may be incidental as co-issuer of the Senior Notes. Since the guarantees are fully unconditional and joint and several of its subsidiaries, except for a few minor subsidiaries, the Partnership has not included condensed consolidated financial information of guarantors of the Senior Notes.

7. Commitments and Contingencies

Legal. The Partnership is involved in various claims, 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.

Environmental. The Partnership is responsible for environmental remediation at certain sites on its gathering and processing systems, resulting primarily from releases of hydrocarbons. The Partnership’s remediation program typically involves the management of contaminated soils and may involve remediation of groundwater. Activities vary with site conditions and locations, the extent and nature of the contamination, remedial requirements and complexity. The ultimate liability and total costs associated with these sites will depend upon many factors.

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The table below reflects the environmental liabilities recorded in the consolidated balance sheet at June 30, 2013 and December 31, 2012 where management believes a loss is probable and reasonably estimable. The Partnership does not have any material environmental remediation matters assessed as reasonably possible that would require disclosure in the financial statements.

	June 30, 2013	December 31, 2012
Current	$2	$5
Noncurrent	10	7
Total environmental liabilities	$12	$12

The Partnership recorded expenditures related to environmental remediation of $3 million for the six months ended June 30, 2013.

Air Quality Control. The Partnership is currently negotiating settlements to certain enforcement actions by the NMED and the TCEQ. The TCEQ recently initiated a state-wide emissions inventory for the sulfur dioxide emissions from sites with reported emissions of 10 tons per year or more. If this data demonstrates that any source or group of sources may cause or contribute to a violation of the National Ambient Air Quality Standards, they must be sufficiently controlled to ensure timely attainment of the standard. This may potentially affect three SUGS recovery units in Texas. It is unclear at this time how the NMED will address the sulfur dioxide standard.

Compliance Orders from the NMED. SUGS has been in discussions with the NMED concerning allegations of violations of New Mexico air regulations related to the Jal #3 and Jal #4 facilities. The NMED has issued amended compliance orders (COs) and proposed penalties for alleged violations at Jal #4 in the amount of $1 million and at Jal #3 in the amount of $7 million. Hearings on the COs were delayed until September 2013 to allow the parties to pursue substantive settlement discussions. SUGS has meritorious defenses to the NMED claims and can offer significant mitigating factors to the claimed violations. The Partnership has recorded a liability related to the claims and will continue to assess its potential exposure to the allegations as the matter progresses.

CDM Sales Tax Audit. CDM Resource Management LLC (“CDM”), a subsidiary of the Partnership, has historically claimed the manufacturing exemption from sales tax in Texas, as is common in the industry. The exemption is based on the fact that CDM's natural gas compression equipment is used in the process of treating natural gas for ultimate use and sale. In a recent audit by the Texas Comptroller's office, the Comptroller has challenged the applicability of the manufacturing exemption to CDM. The period being audited is from August 2006 to August 2007, and liability for that period is potentially covered by an indemnity obligation from CDM's prior owners. CDM may also have liability for periods since 2008, and prospectively, if the Comptroller's challenge is ultimately successful. An audit of the 2008 period has commenced. In April 2013, an independent audit review agreed with the Comptroller's position. While CDM continues to disagree with this position and intends to seek redetermination and other relief, we are unable to predict the final outcome of this matter.

In addition to the matters discussed above, the Partnership is involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business.

8. Series A Preferred Units

On September 2, 2009, the Partnership issued 4,371,586 Series A Preferred Units. As of June 30, 2013, the Series A Preferred Units were convertible to 4,672,835 common units, and if outstanding, are mandatorily redeemable on September 2, 2029 for $80 million plus all accrued but unpaid distributions and interest thereon. The Series A Preferred Units receive fixed quarterly cash distributions of $0.445 per unit if outstanding on the record dates of the Partnership's common unit distributions. Holders can elect to convert Series A Preferred Units to common units at any time in accordance with the partnership agreement.

The following table provides a reconciliation of the beginning and ending balances of the Series A Preferred Units for the six months ended June 30, 2013:

	Units	Amount

Outstanding at beginning of period	4,371,586	$73	
Accretion to redemption value	—	—	
Outstanding at end of period	4,371,586	$73	*

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

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In July 2013, the Partnership was notified by two of the Series A Preferred Units holders of their election to convert their Series A Preferred Units to common units; these holders owned 2.4 million Series A Preferred Units. The total number of common units they will receive is 2.6 million.

9. Related Party Transactions

As of June 30, 2013 and December 31, 2012, details of the Partnership's related party receivables and related party payables were as follows:

	June 30, 2013	December 31, 2012
Related party receivables		
HPC	$1	$1
ETE and its subsidiaries	18	5
Ranch JV	1	2
Total related party receivables	$20	$8
Related party payables		
HPC	$1	$1
ETE and its subsidiaries	41	99
Ranch JV	1	—
Total related party payables	$43	$100

Transactions with ETE and its subsidiaries. Under the service agreement with Services Co., the Partnership pays Services Co.'s direct expenses for services performed, plus an annual fee of $10 million, and receives the benefit of any cost savings recognized for these services. The service agreement had a five year term which was to expire 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. On April 30, 2013, in conjunction with the SUGS Acquisition, the Partnership entered into the first amendment (the "Services Agreement Amendment") to the Services Agreement, effective as of May 26, 2010, by and among the Partnership, ETE and Services Co. The Services Agreement Amendment provided for a waiver of the $10 million annual fee effective as of May 1, 2013 through and including April 30, 2015 and clarified the scope and expenses chargeable as direct expenses thereunder.

On April 30, 2013, the Partnership entered into the second amendment (the "Operation and Service Amendment") to the Operation and Service Agreement (the "Operation and Service Agreement"), by and among the Partnership, ETC, the General Partner and RGS. Under the Operation and Service Agreement, ETC performs certain operations, maintenance and related services reasonably required to operate and maintain certain facilities owned by the Partnership, and the Partnership reimburses 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 Operation and Service Agreement Amendment provides that ETC will no longer provide services for the Partnership's west Texas facilities or for certain south Texas facilities and also defines the services to be provided in the future.

The Partnership incurred total service fees from ETE and its subsidiaries of $2 million and $4 million for the three months ended June 30, 2013 and 2012, respectively, and $7 million and $9 million for the six months ended June 30, 2013 and 2012, respectively.

In conjunction with distributions by the Partnership to the limited and general partner interests, ETE received cash distributions of $15 million and $16 million for each of the three months ended June 30, 2013 and 2012, respectively, and $31 million for the six months ended June 30, 2013 and 2012.

The Partnership's Gathering and Processing segment, in the ordinary course of business, sells natural gas and NGLs to subsidiaries of ETE and records the revenue in gas sales and NGL sales. The Partnership's Contract Services segment provides contract compression and treating services to subsidiaries of ETP and records revenue in gathering, transportation and other fees. The Partnership's Contract Services segment purchased compression equipment from a subsidiary of ETP for $14 million and $25 million for the three and six months ended June 30, 2013.

Transactions with Southern Union. Prior to April 30, 2013, Southern Union provided certain administrative services for SUGS that were either based on SUGS's pro-rata share of combined net investment, margin and certain expenses or direct costs incurred by Southern Union on the behalf of SUGS. Southern Union also charged a management and royalty fee to SUGS for certain management support services provided by Southern Union on the behalf of SUGS and for the use of certain Southern Union

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trademarks, trade names and service marks by SUGS. These administrative services are no longer being provided subsequent to the SUGS Acquisition.

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. The related party general and administrative expenses reimbursed to the Partnership were $4 million and $5 million for the three months ended June 30, 2013 and 2012, respectively, and $10 million and $9 million for the six months ended June 30, 2013 and 2012, respectively, which are recorded in gathering, transportation and other fees.

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

10. Segment Information

During the fourth quarter of 2012, the Partnership realigned the composition of its segments and updated the segment names to reflect the realignment. Accordingly, the Partnership has restated the items of segment information for the three and six months ended June 30, 2012 to reflect this new segment alignment.

The Partnership has five reportable segments: Gathering and Processing, Natural Gas Transportation, NGL Services, Contract Services, and Corporate. The reportable segments are as described below:

- Gathering and Processing. The Partnership provides "wellhead-to-market" services to producers of natural gas, which include transporting raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate NGLs from the raw natural gas and selling or delivering pipeline-quality natural gas and NGLs to various markets and pipeline systems. This segment also includes the Partnership's 33.33% membership interest in Ranch JV, which processes natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in west Texas. The Partnership completed the SUGS Acquisition on April 30, 2013; therefore, the Gathering and Processing segment amounts have been retrospectively adjusted to reflect the SUGS Acquisition beginning March 26, 2012.
- Natural Gas Transportation. The Partnership owns 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, and a 50% membership interest in MEP, which owns a 500 mile interstate natural gas pipeline 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. This segment also includes Gulf States, which owns a 10-mile interstate pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana.
- NGL Services. The Partnership owns a 30% membership interest in Lone Star, an entity owning a diverse set of midstream energy assets including pipelines, storage, fractionation and processing facilities located in Texas, Mississippi and Louisiana.
- Contract Services. The Partnership owns and operates a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems. The Partnership also 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.
- Corporate. The Corporate segment comprises the Partnership's corporate assets.

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 Natural Gas Transportation segments is defined as total revenues, including service fees, less cost of sales. In the Contract Services 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 and revenue generating horsepower. Operation and maintenance expenses are a separate measure used by management to evaluate performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of operation and maintenance expenses. These expenses fluctuate depending on the activities performed during a specific period. The Partnership does not deduct operation and maintenance expenses from total revenues in calculating segment margin because management separately evaluates commodity volume and price changes in segment margin. The Partnership does not record segment margin for its investments in unconsolidated affiliates (HPC, MEP, Lone Star, Ranch JV

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and Grey Ranch) because it records its ownership percentages of their net income as income from unconsolidated affiliates in accordance with the equity method of accounting.

Results for each segment are shown below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
External Revenues				
Gathering and Processing	$583	$462	$1,069	$787
Natural Gas Transportation	—	—	—	—
NGL Services	—	—	—	—
Contract Services	52	44	101	90
Corporate	4	5	9	9
Eliminations	—	—	—	—
Total	$639	$511	$1,179	$886
Intersegment Revenues				
Gathering and Processing	$—	$—	$—	$—
Natural Gas Transportation	—	—	—	—
NGL Services	—	—	—	—
Contract Services	4	5	7	10
Corporate	—	—	—	—
Eliminations	(4)	(5)	(7)	(10)
Total	$—	$—	$—	$—
Segment Margin				
Gathering and Processing	$145	$130	$248	$204
Natural Gas Transportation	—	—	—	1
NGL Services	—	—	—	—
Contract Services	49	45	97	92
Corporate	4	5	9	9
Eliminations	(4)	(5)	(7)	(10)
Total	$194	$175	$347	$296
Operation and Maintenance				
Gathering and Processing	$60	$47	$114	$76
Natural Gas Transportation	—	—	—	—
NGL Services	—	—	—	—
Contract Services	17	15	35	32
Corporate	—	—	—	—
Eliminations	(4)	(5)	(7)	(10)
Total	$73	$57	$142	$98

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The table below provides a reconciliation of total segment margin to (loss) income before income taxes:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Total segment margin	$194	$175	$347	$296
Operation and maintenance	(73)	(57)	(142)	(98)
General and administrative	(18)	(25)	(51)	(57)
Loss on asset sales, net	(1)	(2)	(2)	(2)
Depreciation and amortization	(68)	(69)	(133)	(122)
Income from unconsolidated affiliates	31	34	66	66
Interest expense, net	(41)	(28)	(78)	(57)
Loss on debt refinancing, net	(7)	(8)	(7)	(8)
Other income and deductions, net	(7)	8	(21)	25 *
Income (loss) before income taxes	$10	$28	$(21)	$43

* Other income and deductions, net for the six months ended June 30, 2012 included a one-time producer payment of $16 million related to an assignment of certain contracts.

The tables below provide amounts reflected in the consolidated balance sheet for each segment:

Total Assets	June 30, 2013	December 31, 2012
Gathering and Processing	$4,491	$4,210
Natural Gas Transportation	1,202	1,232
NGL Services	987	948
Contract Services	1,761	1,672
Corporate	80	61
Total	$8,521	$8,123

Investment in Unconsolidated Affiliates	June 30, 2013	December 31, 2012
Gathering and Processing	$36	$35
Natural Gas Transportation	1,201	1,231
NGL Services	987	948
Total	$2,224	$2,214

11. Equity-Based Compensation

The Partnership's LTIP for its employees, directors and consultants authorizes grants up to 5,865,584 common units. LTIP compensation expense of $1 million and $1 million was recorded in general and administrative expense for the three months ended June 30, 2013 and 2012, respectively, and $3 million and $2 million for the six months ended June 30, 2013 and 2012, respectively.

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 or (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. During 2013, all remaining market condition grants were forfeited due to the completion of the three year vesting period without attaining the market based incentive requirements.

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All phantom units granted from November 2010 to November 2012 were service condition grants with graded vesting over five years. Phantom units granted after November 2012 were service condition grants that (1) have graded vesting over five years or (2) vest over the next five years on a cliff basis; by vesting 60% at the end of the third year of service and vesting the remaining 40% at the end of the fifth year of service. 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 six months ended June 30, 2013:

Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at beginning of period	1,231,342	$ 23.22
Service condition grants	52,360	25.30
Vested service condition	(26,158)	23.98
Forfeited service condition	(23,900)	23.45
Forfeited market condition	(44,397)	19.52
Outstanding at end of period	1,189,247	24.43

The Partnership expects to recognize $22 million of compensation expense related to non-vested phantom units over a period of 5 years.

12. Fair Value Measures

The Partnership's financial assets and liabilities measured at fair value on a recurring basis are derivatives related to commodity swaps and embedded derivatives in the Series A Preferred Units. Derivatives related to commodity swaps are valued using discounted cash flow techniques. These techniques incorporate Level 1 and Level 2 inputs such as 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. Embedded derivatives related to Series A Preferred Units are valued using a binomial lattice model. The 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 June 30, 2013			Fair Value Measurements at December 31, 2012		
	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	$7	$7	$—	$ 2	$ 2	$ —
NGLs	4	4	—	1	1	—
Condensate	2	2	—	2	2	—
Total Assets	$13	$13	$—	$ 5	$ 5	$ —
Liabilities:						
Commodity Derivatives:						
Natural Gas	$—	$—	$—	$ 5	$ 5	$ —
NGLs	1	1	—	1	1	—
Embedded Derivatives in Series A Preferred Units	47	—	47	25	—	25
Total Liabilities	$48	$1	$47	$ 31	$ 6	$ 25

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The following table presents the material unobservable inputs used to estimate the fair value of the embedded derivatives in the Series A Preferred Units:

Unobservable Input	June 30, 2013	
Credit Spread	6.39	%
Volatility	20.56	%

Changes in the Partnership's cost of equity and U.S. Treasury yields would cause a change in the credit spread used to value the embedded derivatives. Changes in the Partnership's historical unit price volatility would cause a change in the volatility used to value the embedded derivatives.

The following table presents the changes in Level 3 derivatives measured on a recurring basis for the six months ended June 30, 2013. There were no transfers between the fair value hierarchy levels for the six months ended June 30, 2013.

	Embedded Derivatives in Series A Preferred Units
Net liability balance at December 31, 2012	$25
Change in fair value	22
Net liability balance at June 30, 2013	$47

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 aggregate fair value and carrying amount of the Senior Notes at June 30, 2013 was $2.40 billion and $2.40 billion, respectively. As of December 31, 2012, the aggregate fair value and carrying amount of the Senior Notes was $2.13 billion and $1.96 billion, respectively. The fair value of the Senior Notes is a Level 1 valuation based on third party market value quotations.

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

(Tabular dollar amounts are in millions)

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 (i) our historical condensed consolidated financial statements and the notes included elsewhere in this Quarterly Report on From 10-Q and (ii) our Annual Report on Form 10-K for the year ended December 31, 2012.

OVERVIEW. We are a growth-oriented publicly-traded Delaware limited partnership formed in 2005 engaged in the gathering and processing, compression, treating and transportation of natural gas and the transportation, fractionation and storage of NGLs. We focus on providing midstream services in some of the most prolific natural gas producing regions in the United States, including the Eagle Ford, Haynesville, Barnett, Fayetteville, Marcellus, Utica, Bone Spring, Avalon and Granite Wash shales. Our assets are primarily located in Texas, Louisiana, Arkansas, Pennsylvania, California, Mississippi, Alabama, New Mexico, and the mid-continent region of the United States, which includes Kansas, Colorado and Oklahoma.

RECENT DEVELOPMENTS.

SUGS Acquisition. On April 30, 2013, we and Regency Western acquired SUGS from Southern Union, a wholly owned subsidiary of Holdco, for $1.5 billion. We financed the acquisition by issuing to Southern Union 31,372,419 of our common units and 6,274,483 recently created Class F common units. The Class F common units are not entitled to participate in the Partnership's distributions for twenty-four months post-transaction closing. The remaining $600 million, less $107 million of closing adjustments, was paid in cash. In addition, ETE has agreed to forgo IDR payments on the common units issued with this transaction for the twenty-four months post-transaction closing and to suspend the $10 million annual management fee paid by us for two years post-transaction close.

The SUGS Acquisition expands our presence in the Permian Basin in west Texas, one of the most prolific, high growth, oil and liquids-rich basins in North America.

The common units and Class F common units related to the SUGS Acquisition were issued in a private placement conducted in accordance with the exemption from registration requirements of the Securities Act of 1933, as amended under Section 4(2) thereof. The Class F common units will convert into common units on a one-for-one basis in May 2015.

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The cash portion of the SUGS Acquisition was funded from the proceeds of senior notes issued by the Partnership on April 30, 2013 in a private placement. PEPL Holdings provided a guarantee of collection with respect to the payment of the principal amounts of the senior notes issued by the Partnership.

We accounted for the acquisition in a manner similar to the pooling of interest method of accounting, as it was a transaction between commonly controlled entities. Under this method of accounting, we reflected historical balance sheet data for us and SUGS instead of reflecting the fair market value of SUGS assets and liabilities from the date of acquisition forward. We retrospectively adjusted our financial statements to include the balances and operations of SUGS from March 26, 2012 (the date upon which common control began).

OUR OPERATIONS. We divide our operations into five business segments. During the fourth quarter of 2012, the Partnership realigned the composition of its segments and updated the segment names to reflect the realignment. Accordingly, we have restated segment information for earlier periods to reflect this new segment alignment as follows:

- Gathering and Processing. We provide “wellhead-to-market” services to producers of natural gas, which include transporting raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate NGLs from the raw natural gas and selling or delivering the pipeline-quality natural gas and NGLs to various markets and pipeline systems. This segment also includes ELG and our 33.33% membership interest in Ranch JV, which processes natural gas delivered from the NGLs-rich Bone Spring and Avalon shale formations in west Texas. The Partnership completed the SUGS Acquisition on April 30, 2013; therefore, the Gathering and Processing segment amounts have been retrospectively adjusted to reflect the SUGS Acquisition beginning March 26, 2012.
- Natural Gas Transportation. 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, and a 50% membership interest in MEP, which owns a 500 mile interstate natural gas pipeline 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. This segment also includes Gulf States, which owns a 10-mile interstate pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana.
- NGL Services. We own a 30% membership interest in Lone Star, an entity owning a diverse set of midstream energy assets including pipelines, storage, fractionation and processing facilities located in Texas, Mississippi and Louisiana.
- Contract Services. We own and operate a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems. We also 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.
- Corporate. The Corporate segment comprises our corporate assets.

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, revenue generating horsepower and operation and maintenance expense on a segment and company-wide basis and EBITDA and adjusted EBITDA on a 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 Natural Gas Transportation segment margin as our 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 our investments in unconsolidated affiliates (HPC, MEP, Lone Star, Ranch JV and Grey Ranch) because we record our ownership percentage of their net income as income from unconsolidated affiliates in accordance with the equity method of accounting.

We calculate our Contract Services segment margin as our revenues generated from our contract compression and treating operations minus direct costs, primarily repairs, associated with those revenues.

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We calculate total segment margin as the total 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, the 40% of ELG margin attributable to the holder of the noncontrolling interest and our 33.33% portion of Ranch JV margin. 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 product purchases and sales, a key component of our operations.
Revenue Generating Horsepower. Revenue generating horsepower is the primary driver for revenue growth in compression services for our Contract Service segment, and it is also the primary measure for evaluating our operational efficiency. Revenue generating horsepower is the total horsepower that our Contract Services segment owns and operates for external customers. It does not include horsepower under contract that is not generating revenue or idle horsepower.
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 expense from total revenues in calculating segment margin because we use segment margin to separately evaluate commodity volume and price changes.
EBITDA and Adjusted EBITDA. We define EBITDA as net income (loss) plus interest expense, provision for income taxes 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 ELG;
- Partnership's interest in ELG adjusted EBITDA; and
- our interest in adjusted EBITDA from unconsolidated affiliates less income from unconsolidated affiliates.

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 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. EBITDA and adjusted EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate EBITDA or adjusted EBITDA in the same manner.
Adjusted EBITDA is the starting point in determining distributable cash flow, which is an important non-GAAP financial measure for a publicly traded partnership.

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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 (loss) income for the Partnership:

	Six Months Ended June 30,	
Reconciliation of "Adjusted EBITDA" to net cash flows provided by operating activities and net (loss) income	2013	2012
Net cash flows provided by operating activities	$195	$102
Add (deduct):		
Depreciation and amortization, including debt issuance cost amortization and bond premium write-off and amortization	(137)	(125)
Income from unconsolidated affiliates	66	66
Derivative valuation change	(17)	18
Loss on asset sales, net	(2)	(2)
Unit-based compensation expenses	(3)	(2)
Trade accounts receivable, accrued revenues and related party receivables	41	(29)
Other current assets and other current liabilities	51	(3)
Trade accounts payable, accrued cost of gas and liquids, related party payables and deferred revenues	(10)	69
Distributions of earnings received from unconsolidated affiliates	(71)	(63)
Cash flow changes in other assets and liabilities	(131)	12
Net (loss) income	(18)	43
Add (deduct):		
Interest expense, net	78	57
Depreciation and amortization expense	133	122
Income tax benefit	(3)	—
EBITDA	190	222
Add (deduct):		
Partnership's interest in unconsolidated affiliates' adjusted EBITDA	123	116
Income from unconsolidated affiliates	(66)	(66)
Non-cash loss (gain) from commodity and embedded derivatives	14	(24)
Other expense, net	13	9
Adjusted EBITDA	$274	$257

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The following tables present reconciliations of net income to adjusted EBITDA for our unconsolidated affiliates, on a 100% basis, and the Partnership's interest in adjusted EBITDA for the three and six months ended June 30, 2013 and 2012:

	Six Months Ended June 30, 2013					
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch	Total
Net income (loss)	$38	$42	$99	$1	$(1)	
Add:						
Depreciation and amortization	18	35	40	3	—	
Interest expense, net	1	26	—	—	—	
Adjusted EBITDA	57	103	139	4	(1)	
Ownership interest	49.99%	50%	30%	33.33%	50%	
Partnership's interest in adjusted EBITDA	$28	$52	$42	$1	$(1)	$123

	Six Months Ended June 30, 2012					
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch	Total
Net income	$49	$42	$79	$—	$—	
Add:						
Depreciation and amortization	18	34	25	—	—	
Interest expense, net	1	26	—	—	—	
Adjusted EBITDA	68	102	104	—	—	
Ownership interest	49.99%	50%	30%	33.33%	50%	
Partnership's interest in adjusted EBITDA	$34	$51	$31	$—	$—	$116

The following table presents a reconciliation of total segment margin and adjusted total segment margin to net (loss) income for the three and six months ended June 30, 2013 and 2012 for the Partnership:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net income (loss)	$11	$28	$(18)	$43
Add (deduct):				
Operation and maintenance	73	57	142	98
General and administrative	18	25	51	57
Loss on asset sales, net	1	2	2	2
Depreciation and amortization	68	69	133	122
Income from unconsolidated affiliates	(31)	(34)	(66)	(66)
Interest expense, net	41	28	78	57
Loss on debt refinancing, net	7	8	7	8
Other income and deductions, net	7	(8)	21	(25)
Income tax benefit	(1)	—	(3)	—
Total segment margin	194	175	347	296
Add (deduct):				
Non-cash gain from commodity derivatives	(12)	(14)	(8)	(16)
Segment margin related to noncontrolling interest	(2)	(1)	(3)	(3)
Segment margin related to ownership percentage in Ranch JV	1	—	2	—
Adjusted total segment margin	$181	$160	$338	$277

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Three Months Ended June 30, 2013 vs. Three Months Ended June 30, 2012

	Three Months Ended June 30,			
	2013	2012	Change	Percent
Total revenues	$639	$511	$128	25 %
Cost of sales	445	336	(109)	32
Total segment margin [1]	194	175	19	11
Operation and maintenance	73	57	(16)	28
General and administrative	18	25	7	28
Loss on asset sales, net	1	2	1	50
Depreciation and amortization	68	69	1	1
Operating income	34	22	12	55
Income from unconsolidated affiliates	31	34	(3)	9
Interest expense, net	(41)	(28)	(13)	46
Loss on debt refinancing, net	(7)	(8)	1	13
Other income and deductions, net	(7)	8	(15)	188
Income before income taxes	10	28	(18)	64
Income tax benefit	(1)	—	1	100
Net income	11	28	(17)	61
Net income attributable to noncontrolling interest	(1)	(1)	—	—
Net income attributable to Regency Energy Partners LP	$10	$27	$(17)	63
Gathering and processing segment margin	$145	$130	$15	12
Non-cash gain from commodity derivatives	(12)	(14)	2	14
Segment margin related to noncontrolling interest	(2)	(1)	(1)	100
Segment margin related to ownership percentage in Ranch JV	1	—	1	100
Adjusted gathering and processing segment margin	132	115	17	15
Natural gas transportation segment margin	—	—	—	—
Contract services segment margin [2]	49	45	4	9
Corporate segment margin	4	5	(1)	20
Intersegment eliminations [2]	(4)	(5)	1	20
Adjusted total segment margin	$181	$160	$21	13 %

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

(2) Contract Services segment margin includes intersegment revenues of $4 million and $5 million for the three months ended June 30, 2013 and 2012, respectively. These intersegment revenues were eliminated upon consolidation.

Net Income Attributable to Regency Energy Partners LP. We had a net income of $10 million for the three months ended June 30, 2013 compared to net income of $27 million for the three months ended June 30, 2012. The major components of this change were as follows:

- $19 million increase in total segment margin primarily due to increased volumes in south and west Texas in our Gathering and Processing segment;
- $7 million decrease in general and administrative expense primarily due to a decrease in the management fee paid to ETE and employee expenses; offset by
- $16 million increase in operation and maintenance expense primarily due to increases in plant and pipeline maintenance and materials expenses and employee expenses primarily due to organic growth in south and west Texas.
- $15 million decrease in other income and deductions, net primarily due to an $8 million non-cash loss on the mark-to-market of the embedded derivative related to the Series A Preferred Units in for the three months ended June 30,

2013; and

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- $13 million increase in interest expense, net primarily due to the issuance of $700 million senior notes issued in October 2012 with in interest rate of 5.5% and $600 million senior notes issued in April 2013 with an interest rate of 4.5%.

Adjusted Total Segment Margin. Adjusted total segment margin increased to $181 million in the three months ended June 30, 2013 from $160 million in the three months ended June 30, 2012. The major components of this change were as follows:

- Adjusted Gathering and Processing segment margin increased to $132 million during the three months ended June 30, 2013 from $115 million for the three months ended June 30, 2012 primarily due to volume growth in south and west Texas and north Louisiana. Total Gathering and Processing throughput increased to 2,178,000 MMBtu/d during the three months ended June 30, 2013 from 1,839,000 MMBtu/d during the three months ended June 30, 2012. Total NGL gross production increased to 89,100 Bbls/d during the three months ended June 30, 2013 from 77,800 Bbls/d during the three months ended June 30, 2012;
- Contract Services segment margin increased to $49 million in the three months ended June 30, 2013 from $45 million for the three months ended June 30, 2012. As of June 30, 2013 and 2012, total revenue generating horsepower was 938,000 and 825,000, inclusive of 41,000 and 86,000 respectively, of revenue generating horsepower utilized by our Gathering and Processing segment; and
- Intersegment eliminations decreased to $4 million in the three months ended June 30, 2013 from $5 million in the three months ended June 30, 2012. The decrease was primarily due to a decrease in intersegment revenue between the Gathering and Processing segment and the Contract Services segment associated with certain assets in south Texas.

Operation and Maintenance. Operation and maintenance expense increased to $73 million in the three months ended June 30, 2013 from $57 million during the three months ended June 30, 2012. The change was primarily due to the following:

- $6 million increase in pipeline and plant maintenance and materials expenses primarily due to organic growth in south and west Texas;
- $5 million increase in employee expenses due to increases in contract labor and overtime related to organic growth in south and west Texas; and
- $4 million increase in outside services primarily due to an increase in environmental expenses and equipment rentals.

General and Administrative. General and administrative expense decreased to $18 million in the three months ended June 30, 2013 from $25 million during the three months ended June 30, 2012. The change was primarily due to the following:

- $3 million decrease in employee related expenses due to a decrease in headcount;
- $2 million decrease in other expenses primarily due to a decrease in the management fee paid to ETE as a result of a two year holiday of this fee which began on April 30, 2013; and
- $2 million decrease in professional fees primarily due to an insurance settlement reimbursement.

Depreciation and Amortization. Depreciation and amortization expense decreased to $68 million in the three months ended June 30, 2013 from $69 million in the three months ended June 30, 2012.

Income from Unconsolidated Affiliates. Income from unconsolidated affiliates decreased to $31 million for the three months ended June 30, 2013 from $34 million for the three months ended June 30, 2012. The schedule below summarizes the components of income from unconsolidated affiliates and our ownership interest for the three months ended June 30, 2013 and 2012, respectively:

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	Three Months Ended June 30, 2013					
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch	Total
Net income (loss)	$18	$21	$44	$1	$(1)	
Ownership interest	49.99%	50%	30%	33.33%	50%	
Share of unconsolidated affiliates' net income	9	10	13	—	—	
Less: Amortization of excess fair value of unconsolidated affiliates	(1)	—	—	—	—	
Income from unconsolidated affiliates	$8	$10	$13	$—	$—	$31

	Three Months Ended June 30, 2012					
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch	Total
Net income	$26	$21	$41	$—	$—	
Ownership interest	49.99%	50%	30%	33.33%	50%	
Share of unconsolidated affiliates' net income	13	10	12	—	—	
Less: Amortization of excess fair value of unconsolidated affiliates	(1)	—	—	—	—	
Income from unconsolidated affiliates	$12	$10	$12	$—	$—	$34

HPC's net income decreased to $18 million for the three months ended June 30, 2013 from $26 million for the three months ended June 30, 2012, primarily due to the expiration of certain contracts that were not renewed as well as a customer declaring bankruptcy on April 1, 2013, which contributed $1 million to the decrease. We expect that the annual impact resulting from the loss of this customer, if we are unable to replace the firm commitment contract, would be a reduction of approximately $5 million. MEP's net income was $21 million for the three months ended June 30, 2013 and June 30, 2012. Lone Star's net income increased to $44 million for the three months ended June 30, 2013 from $41 million for the three months ended June 30, 2012, primarily due to the addition of the West Texas Gateway NGL Pipeline and Lone Star Fractionator I placed into service in December 2012.

The following table presents operational data for each of our unconsolidated affiliates for the three months ended June 30, 2013 and 2012:

		Three Months Ended June 30,	
	Operational data	2013	2012
HPC	Throughput (MMBtu/d)	657,950	903,344
MEP	Throughput (MMBtu/d)	1,263,734	1,418,206
Lone Star	NGL Transportation – Total Volumes (Bbls/d)	162,552	133,429
	Refinery – Geismar Throughput (Bbls/d)	14,748	20,575
	Fractionation – Throughput Volume (Bbls/d)	86,947	*
Ranch JV	Throughput (MMBtu/d)	68,522	4,744

*Fractionator I began operations in December 2012.

**Ranch JV had not begun operations.

Interest Expense, Net. Interest expense, net increased to $41 million for the three months ended June 30, 2013 from $28 million for the three months ended June 30, 2012, primarily due to the interest related to our $700 million senior notes issued in October 2012 with an interest rate of 5.5% as well as the interest related to our $600 million senior notes issued April 30, 2013 in connection with the SUGS Acquisition with an interest of 4.5%.

Other Income and Deductions, Net. Other income and deductions, net decreased to a loss of $7 million in the three months ended June 30, 2013 from a gain of $8 million in the three months ended June 30, 2012, primarily due to to an $8 million non-cash loss on the mark-to-market of the embedded derivative related to the Series A Preferred Units in June 2013.

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Six Months Ended June 30, 2013 vs. Six Months Ended June 30, 2012

	Six Months Ended June 30,			
	2013	2012	Change	Percent
Total revenues	$1,179	$886	$293	33 %
Cost of sales	832	590	(242)	41
Total segment margin [(1)]	347	296	51	17
Operation and maintenance	142	98	(44)	45
General and administrative	51	57	6	11
Loss on asset sales, net	2	2	—	—
Depreciation and amortization	133	122	(11)	9
Operating income	19	17	2	12
Income from unconsolidated affiliates	66	66	—	—
Interest expense, net	(78)	(57)	(21)	37
Loss on debt refinancing, net	(7)	(8)	1	13
Other income and deductions, net	(21)	25	(46)	184
Income before income taxes	(21)	43	(64)	149
Income tax benefit	(3)	—	3	100
Net (loss) income	(18)	43	(61)	142
Net income attributable to noncontrolling interest	(1)	(1)	—	—
Net (loss) income attributable to Regency Energy Partners LP	$(19)	$42	$(61)	145
Gathering and processing segment margin	$248	$204	$44	22
Non-cash gain from commodity derivatives	(8)	(16)	8	50
Segment margin related to noncontrolling interest	(3)	(3)	—	—
Segment margin related to ownership percentage in Ranch JV	2	—	2	100
Adjusted gathering and processing segment margin	239	185	54	29
Natural gas transportation segment margin	—	1	(1)	100
Contract services segment margin [(2)]	97	92	5	5
Corporate segment margin	9	9	—	—
Intersegment eliminations [(2)]	(7)	(10)	3	30
Adjusted total segment margin	$338	$277	$61	22 %

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

(2) Contract Services segment margin includes intersegment revenues of $7 million and $10 million for the six months ended June 30, 2013 and 2012, respectively. These intersegment revenues were eliminated upon consolidation.

Net (Loss) Income Attributable to Regency Energy Partners LP. We had a net loss of $19 million for the six months ended June 30, 2013 compared to net income of $42 million for the six months ended June 30, 2012. The major components of this change were as follows:

- $51 million increase in total segment margin primarily due to increased volumes in south and west Texas in our Gathering and Processing segment and six months contribution from the SUGS assets in 2013 versus three months contribution in 2012;
- $6 million decrease in general and administrative expense primarily due to decreases in employee expenses and a decrease in the management fee paid to ETE; offset by
- $46 million decrease in other income and deductions, net primarily due to a $22 million non-cash loss on the mark-to-market of the embedded derivative related to the Series A Preferred Units for the six months ended June 30, 2013 and the absence of a $16 million one-time producer payment received in March 2012 related to an assignment of certain

contracts;

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- $44 million increase in operation and maintenance expense primarily due to six months of activity from the SUGS assets in 2013 versus three months in 2012, organic growth in south and west Texas and ad valorem taxes;
- $21 million increase in interest expense, net primarily due to the issuance of $700 million senior notes issued in October 2012 with an interest rate of 5.5% and $600 million senior notes issued in April 2013 with an interest rate of 4.5%; and
- $11 million increase in depreciation and amortization primarily related to ongoing growth projects.

Adjusted Total Segment Margin. Adjusted total segment margin increased to $338 million in the six months ended June 30, 2013 from $277 million in the six months ended June 30, 2012. The major components of this change were as follows:

- Adjusted Gathering and Processing segment margin increased to $239 million during the six months ended June 30, 2013 from $185 million for the six months ended June 30, 2012 primarily due to volume growth in south and west Texas and north Louisiana and six months contribution from the SUGS assets in 2013 versus three months contribution in 2012. Total Gathering and Processing throughput increased to 2,084,000 MMBtu/d during the six months ended June 30, 2013 from 1,604,000 MMBtu/d during the six months ended June 30, 2012. Total NGL gross production increased to 86,000 Bbls/d during the six months ended June 30, 2013 from 57,800 Bbls/d during the six months ended June 30, 2012;
- Contract Services segment margin increased to $97 million in the six months ended June 30, 2013 from $92 million in the six months ended June 30, 2012. As of June 30, 2013 and 2012, total revenue generating horsepower was 938,000 and 825,000, inclusive of 41,000 and 86,000, respectively, of revenue generating horsepower utilized by our Gathering and Processing segment; and
- Intersegment eliminations decreased to $7 million in the six months ended June 30, 2013 from $10 million in the six months ended June 30, 2012. The decrease was primarily due to a decrease in intersegment revenue between the Gathering and Processing segment and the Contract Services segment associated with certain assets in south Texas.

Operation and Maintenance. Operation and maintenance expense increased to $142 million in the six months ended June 30, 2013 from $98 million during the six months ended June 30, 2012. The change was primarily due to six months of activity from the SUGS assets in 2013 versus three months in 2012, which resulted in $35 million increase, with the remaining increase attributable to organic growth in south and west Texas and ad valorem taxes.

General and Administrative. General and administrative expense decreased to $51 million in the six months ended June 30, 2013 from $57 million during the six months ended June 30, 2012. The change was primarily due to a $4 million decrease in employee expenses primarily due to a decrease in headcount and management incentive expenses and a $2 million decrease in the management fee paid to ETE.

Depreciation and Amortization. Depreciation and amortization expense increased to $133 million in the six months ended June 30, 2013 from $122 million in the six months ended June 30, 2012. This increase was the result of $18 million additional depreciation and amortization expense due to the completion of various organic growth projects since July 2012 and because 2012 only included three months of depreciation for the SUGS assets, offset by the absence of $7 million related to an "out-of-period" adjustment for all periods subsequent to May 26, 2010 (the "Successor" period as described in our Form 10-K for the year ended December 31, 2012) related to our Contract Services segment to adjust the estimated useful lives of certain assets to comply with our policy. Had these amounts been recorded in their respective period, the depreciation and amortization expense for the quarter ended June 30, 2012 would have been $115 million.

Income from Unconsolidated Affiliates. Income from unconsolidated affiliates was $66 million for the six months ended June 30, 2013 and 2012. The schedule below summarizes the components of income from unconsolidated affiliates and our ownership interest for the six months ended June 30, 2013 and 2012, respectively:

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	Six Months Ended June 30, 2013					
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch	Total
Net income (loss)	$38	$42	$99	$1	$(1)	
Ownership interest	49.99%	50%	30%	33.33%	50%	
Share of unconsolidated affiliates' net income	19	20	30	—	—	
Less: Amortization of excess fair value of unconsolidated affiliates	(3)	—	—	—	—	
Income from unconsolidated affiliates	$16	$20	$30	$—	$—	$66

	Six Months Ended June 30, 2012					
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch	Total
Net income	$49	$42	$79	$—	$—	
Ownership interest	49.99%	50%	30%	33.33%	50%	
Share of unconsolidated affiliates' net income	24	21	24	—	—	
Less: Amortization of excess fair value of unconsolidated affiliates	(3)	—	—	—	—	
Income from unconsolidated affiliates	$21	$21	$24	$—	$—	$66

HPC's net income decreased to $38 million for the six months ended June 30, 2013 from $49 million for the six months ended June 30, 2012, primarily due to the expiration of certain contracts that were not renewed as well as a customer declaring bankruptcy on April 1, 2013, which contributed $2 million to the decrease. We expect that the annual impact resulting from the loss of this customer, if we are unable to replace the firm commitment contract, would be a reduction of approximately $5 million. MEP's net income was $42 million for the six months ended June 30, 2013 and June 30, 2012. Lone Star's net income increased to $99 million for the six months ended June 30, 2013 from $79 million for the six months ended June 30, 2012, primarily due to the addition of the West Texas Gateway NGL Pipeline and Lone Star Fractionator I placed into service in December 2012.

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The following table presents operational data for each of our unconsolidated affiliates for the six months ended June 30, 2013 and 2012:

		Six Months Ended June 30,	
	Operational data	2013	2012
HPC	Throughput (MMBtu/d)	685,877	922,241
MEP	Throughput (MMBtu/d)	1,363,020	1,423,764
Lone Star	NGL Transportation – Total Volumes (Bbls/d)	158,023	134,022
	Refinery – Geismar Throughput (Bbls/d)	15,983	19,910
	Fractionation – Throughput Volume (Bbls/d)	69,072	*
Ranch JV	Throughput (MMBtu/d)	60,802	4,744

*Fractionator I began operations in December 2012.

**Ranch JV had not begun operations.

Interest Expense, Net. Interest expense, net increased to $78 million for the six months ended June 30, 2013 from $57 million for the six months ended June 30, 2012, primarily due to the interest related to our $700 million senior notes issued in October 2012 with an interest rate of 5.5% as well as the issuance of our $600 million senior notes issued in April 2013 in connection with the SUGS Acquisition, with an interest rate of 4.5%.

Other Income and Deductions, Net. Other income and deductions, net decreased to a loss of $21 million in the six months ended June 30, 2013 from a gain of $25 million in the six months ended June 30, 2012, primarily due to a $22 million non-cash loss on the mark-to-market of the embedded derivative related to the Series A Preferred Units in June 2013 and the absence of a $16 million one-time producer payment received in March 2012 related to an assignment of certain contracts.

In July 2013, we were notified by two of the Series A Preferred Units holders of their election to convert their Series A Preferred Units to common units; these holders owned 2.4 million Series A Preferred Units. The total number of common units they will receive is 2.6 million.

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, 2012.

OTHER MATTERS

Information regarding our commitments and contingencies is included in Note 7 – Commitments and Contingencies to the condensed consolidated financial statements included in Item 1 of this report.

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LIQUIDITY AND CAPITAL RESOURCES

Liquidity

We expect our sources of liquidity to include:

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

We expect our 2013 capital expenditures, including capital contributions to our unconsolidated affiliates and SUGS, to be as follows (in millions):

	2013
Growth Capital Expenditures	
Gathering and Processing	$465
NGL Services	175
Contract Services	160
Total	$800
Maintenance Capital Expenditures; including our proportionate share related to our unconsolidated affiliates	$45

We may revise the timing of these expenditures as necessary to adapt to economic or business 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 the fair value changes of current derivative assets and liabilities. These derivative assets and liabilities represent our expectations for the settlement of derivative rights and obligations over the next 12 months, 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 Services segment records deferred revenues as a current liability. The deferred revenue represents billings in advance of services performed. As the revenues associated with the deferred revenues are earned, the liability is reduced.

We had a working capital deficit of $64 million at June 30, 2013 compared to a working capital deficit of $149 million at December 31, 2012. The decrease in the working capital deficit was primarily due to a $64 million decrease in related party payables, net of related party receivables and a $49 million decrease in other current liabilities, primarily due to payments of interest on senior notes offset by a $36 million decrease in cash and cash equivalents

Cash Flows from Operating Activities. Net cash flows provided by operating activities increased to $195 million in the six months ended June 30, 2013 from $102 million in the six months ended June 30, 2012, primarily as a result of an increase in operating cash flow generated by changes in other assets and liabilities as a result of our acquisition of SUGS, the non-cash derivative value change, and an increase in distributions of earnings received from unconsolidated affiliates, offset by a decrease in net income.

Cash Flows used in Investing Activities. Net cash flows used in investing activities increased to $958 million in the six months ended June 30, 2013 from $359 million in the six months ended June 30, 2012, primarily as a result of $463 million attributable to our acquisition of SUGS and increased capital expenditures for the growth projects described below, partially offset by a decrease in contributions to unconsolidated affiliates.

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 six months ended June 30, 2013, we incurred $435 million of growth capital expenditures, inclusive of contributions to unconsolidated

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affiliates. Growth capital expenditures for the six months ended June 30, 2013 were primarily related to $235 million for our Gathering and Processing segment, $65 million for our NGL Services segment, and $135 million for our Contract Services 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 six months ended June 30, 2013, we incurred $20 million of maintenance capital expenditures.

Cash Flows from Financing Activities. Net cash flows provided by financing activities increased to $727 million in the six months ended June 30, 2013 from $272 million during the same period in 2012. The increase is primarily due to our issuance of $600 million of senior notes, proceeds of which were used for the SUGS acquisition, and borrowings under our credit facility of $343 million. These increases were partially offset by the redemption of senior notes, an increase in distributions to our partners and decrease in proceeds from common unit offerings.

Capital Resources

Revolving Credit Facility. In May 2013, RGS entered into the Sixth Amended and Restated Credit Agreement to increase the commitment to $1.2 billion with a $300 million uncommitted incremental facility and extend the maturity date to May 21, 2018. The material differences between the Fifth and Sixth Amended and Restated Credit Agreement include:

- A 75 bps decrease in pricing, with an additional 50 bps decrease upon the achievement of an investment grade rating by the Borrower;
- No limitation on the maximum amount that the loan parties may invest in joint ventures existing on the date of the credit agreement so long as the Borrower is in pro forma compliance with the financial covenants;
- The addition of a “Restricted Subsidiary” structure such that certain designated subsidiaries are not subject to the credit facility covenants and do not guarantee the obligations thereunder or pledge their assets in support thereof;
- The addition of provisions such that upon the achievement of an investment grade rating by the Borrower, the collateral package will be released; the facility will become unsecured; and the covenant package will be significantly reduced;
- An eight-quarter increase in the permitted Total Leverage Ratio; and
- After March 2015, an increase in the permitted Total Leverage Ratio for two fiscal quarters following any $50 million or greater acquisition.

The new credit agreement and the guarantees are senior to our and the guarantors' secured obligations, including the Series A Preferred Units, to the extent of the value of the assets securing such obligations. As of June 30, 2013, we were in compliance with all of the financial covenants contained within the new credit agreement.

We treated the May 2013 amendment of the revolving credit facility as a modification of an existing revolving credit agreement and, therefore, wrote off debt issuance costs of $0.5 million to interest expense, net in the period from January 1, 2013 to June 30, 2013. In addition, we paid and capitalized $7 million of loan fees which will be amortized over the remaining term.

Senior Notes Offering. In April 2013, in conjunction with the closing of the SUGS Acquisition, the Partnership and Finance Corp. issued $600 million senior notes in a private placement (the “2023 4.5% Notes”) pursuant to Section 4(2) of the Securities Act. The 2023 4.5% Notes bear interest at 4.5% payable semi-annually in arrears on May 1 and November 1, commencing November 1, 2013 and maturing on November 1, 2023.

At any time prior to August 1, 2023, we may redeem some or all of the 2023 4.5% Notes at a price equal to 100% of the principal amount plus a make-whole premium and accrued interest. On or after August 1, 2023, we may redeem some or all of the 2023 4.5% Notes at a price equal to 100% plus accrued interest.

Upon a change of control, as defined in the indenture, followed by a ratings decline within 90 days, each holder of the 2023 4.5% Notes will be entitled to require us to purchase all or a portion of its notes at a purchase price of 101% of the principal amount plus accrued interest and liquidated damages, if any. Our ability to purchase the notes upon a change of control will be limited by the terms of our debt agreements, including our revolving credit facility.

The 2023 4.5% Notes contain various covenants that limit, among other things, our ability, and the ability of certain of our subsidiaries, to:

- incur additional indebtedness;

- pay distributions on, or repurchase or redeem equity interest;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and

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- sell assets, consolidate or merge with or into other companies.

If the 2023 4.5% Notes achieve investment grade ratings by both Moody's and S&P and no default or event or default has occurred and is continuing, we will no longer be subject to many of the foregoing covenants.

The 2023 4.5% Notes are jointly and severally guaranteed by all of our consolidated subsidiaries, other than Finance Corp. and a minor subsidiary. PEPL Holdings provided a guarantee of collection with respect to the payment of the principal amounts of the senior notes issued by us. The 2023 4.5% Notes and the guarantees are unsecured and rank equally with all of our and the guarantors' existing and future unsecured obligations. The 2023 4.5% Notes and the guarantees will be senior in right of payment to any of our and the guarantor's future obligations that are, by their terms, expressly subordinated in right of payment to the notes and the guarantees. The 2023 4.5% Notes and the guarantees will be effectively subordinated to our and the guarantors' secured obligations, including our revolving credit facility, to the extent of the value of the assets securing and obligations.

Senior Notes Redemption. In June 2013, the Partnership redeemed all of the $163 million outstanding 9.375% Senior Notes due 2016 for $178 million cash, inclusive of accrued and unpaid interest of $7 million and other fees and expenses.

Cash Distributions from Unconsolidated Affiliates. The following table summarizes the cash distributions from unconsolidated affiliates for the three and six months ended June 30, 2013 and 2012:

	Six Months Ended June 30,	
	2013	2012
HPC	$30	$30
MEP	38	38
Lone Star	40	18
	$108	$86

The increase in the Lone Star distribution is primarily attributable to the addition of the West Texas Gateway NGL Pipeline and Lone Star Fractionator I placed into service in December 2012.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Risk and Accounting Policies. We are exposed to market risks associated with commodity prices, counterparty credit and interest rates. Our 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 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 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 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 have swap contracts that settle against certain NGLs, condensate and natural gas market prices.

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The following table sets forth certain information regarding our hedges outstanding at June 30, 2013. 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.

June 30, 2013

Period	Underlying	Notional Volume/ Amount		We Pay	We Receive Weighted Average Price			Fair Value Asset/ (Liability) (in millions)	Effect of Hypothetical Change in Index*
July 2013-December 2013	Propane	488	(MBbls)	Index	$	0.93	($/gallon)	2	2
July 2013-December 2014	Normal Butane	234	(MBbls)	Index	$	1.43	($/gallon)	2	1
July 2013-December 2014	West Texas Intermediate Crude	700	(MBbls)	Index	$	94.91	($/Bbl)	1	7
July 2013-December 2014	Natural Gas	18,672,000	(MMBtu)	Index	$	4.14	($/MMBtu)	7	7
					Total Fair Value			$12	

* 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. 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 Chief Financial Officer of our General Partner, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rule 13a–15(e) and 15d–15(e) of the Exchange Act). Based on management's evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective in achieving that level of reasonable assurance as of June 30, 2013.

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 June 30, 2013 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

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

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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, 2012. Except as discussed 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, 2012.

Increased regulation of hydraulic fracturing could result in reductions or delays in drilling and completing new oil and natural gas wells, which could adversely impact our revenues by decreasing the volumes of natural gas that we gather, process and transport.

Certain of our customers' natural gas is developed from formations requiring hydraulic fracturing as part of the completion process. Fracturing is a process where water, sand and chemicals are injected under pressure into subsurface formations to stimulate production. While the underground injection of fluids is regulated by the EPA under the Safe Drinking Water Act, fracturing is excluded from regulation unless the injection fluid is diesel fuel. Congress has recently considered legislation that would repeal the exclusion, allowing the EPA to more generally regulate fracturing, and requiring disclosure of chemicals used in the fracturing process. If enacted, such legislation could require fracturing to meet permitting and financial responsibility, siting and technical specifications relating to well construction, plugging and abandonment. The EPA is also considering various regulatory programs directed at hydraulic fracturing. For example, on October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the federal Clean Water Act to further regulate wastewater discharged from hydraulic fracturing and other natural gas production. In November 2011, the EPA indicated it may initiate rulemaking under the Toxic Substances Control Act to obtain data regarding the composition of hydraulic fracturing fluids. The adoption of new federal laws or regulations imposing reporting obligations on, or otherwise limiting or regulating, the hydraulic fracturing process could make it more difficult to complete oil and natural gas wells in shale formations, and increase our customers' costs of compliance. In addition, the EPA is currently studying the potential adverse impact that each stage of hydraulic fracturing may have on the environment. Results of the study are expected by 2014. Several states in which our customers operate have also adopted regulations requiring disclosure of fracturing fluid components or otherwise regulate their use more closely.

On April 17, 2012, the EPA approved final rules establishing new air emission standards for oil and natural gas production and natural gas processing operations. This rulemaking addresses emissions of various pollutants frequently associated with oil and natural gas production and processing activities. For new or reworked hydraulically-fractured wells, the final rule requires controlling emissions through flaring until 2015, when the rule requires the use of reduced emission (or “green”) completions, meaning equipment must be installed to separate gas and liquid hydrocarbons at the well head, enabling gas capture. The rule also establishes specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants and certain other equipment. These rules may require a number of modifications to our and our customers' operations, including the installation of new equipment to control emissions. In addition, the U.S. Department of the Interior published a revised proposed rule on May 24, 2013 that would update existing regulation of hydraulic fracturing activities on federal lands, including requirements for chemical disclosure, well bore integrity and handling of flowback water. Compliance with these rules could result in additional costs, including increased capital expenditures and operating costs, for us and our customers, which may adversely impact our business.

Additional federal or state legislation or regulation of hydraulic fracturing or related activities could result in operational delays, increased operating costs, and additional regulatory burdens on exploration and production operators. This could reduce production of natural gas and, in turn, adversely affect our revenues and results of operations by decreasing the volumes of natural gas and NGLs that we gather, process and transport.

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Item 6. Exhibits
The exhibits listed below are filed as a part of this report:

	Exhibit Number	Description
*	1.1	Purchase Agreement dated as of April 24, 2013 among Regency Energy Partners LP, Regency Energy Finance Corp., certain subsidiaries of Regency Energy Partners LP party thereto and J.P. Morgan Securities LLC, as representative of the several initial purchasers.
**	2.1	Amendment No. 1 to Contribution Agreement dated as of April 16, 2013, with the related Form of Guarantee of Collection.
*	3.1	Amendment No. 8 to Amended and Restated Agreement of Limited Partnership of Regency Energy Partners LP, dated as of April 30, 2013.
*	4.1	Indenture dated as of April 30, 2013 among Regency Energy Partners LP, Regency Energy Finance Corp., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee.
*	4.2	Registration Rights Agreement, dated as of April 30, 2013, by and between Southern Union Company and Regency Energy Partners LP.
*	4.3	Registration Rights Agreement, dated as of April 30, 2013, among Regency Energy Partners LP, Regency Energy Finance Corp., certain subsidiaries of Regency Energy Partners LP party thereto, PEPL Holdings, LLC and J.P. Morgan Securities LLC, as representative of the several initial purchasers.
*	10.1	First Amendment to Services Agreement, dated April 30, 2013, by and among ETE Services Company, LLC, Energy Transfer Equity, L.P. and Regency Energy Partners LP.
*	10.2	Second Amendment to Operation and Service Agreement, dated April 30, 2013, by and among La Grange Acquisition, L.P. d/b/a Energy Transfer Company, Regency GP LP, Regency Energy Partners LP and Regency Gas Services LP.
*	10.3	Guarantee of Collection, dated as of April 30, 2013, between PEPL Holdings, LLC and Regency Energy Partners, LP.
***	10.4	Sixth Amended and Restated Credit Agreement, dated May 21, 2013
	31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
	31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
****	32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
****	32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

* Indicates exhibit incorporated by reference to Regency Energy Partners LP Current Report on Form 8-K filed on April 30, 2013.

** Indicates exhibit incorporated by reference to Regency Energy Partners LP Current Report on Form 8-K filed on April 16, 2013.

*** Indicates exhibit incorporated by reference to Regency Energy Partners LP Current Report on Form 8-K filed on May 28, 2013.

**** Furnished herewith

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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: August 8, 2013	/S/ A. TROY STURROCK A. Troy Sturrock Vice President, Controller and Principal Accounting Officer (Duly Authorized Officer)