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

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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 w believe our forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, we cannot give assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions including without limitation the following:

- volatility in the price of oil, natural gas, 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		