Regency Energy Partners LP
Form 10-Q
November 07, 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 September 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 210,714,852 common units and 6,274,483 Class F common units outstanding as of November 1, 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
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
Lone Star	Lone Star NGL LLC
LTIP	Long-Term Incentive Plan
MBbls	One thousand barrels
MEP	Midcontinent Express Pipeline LLC
MMBtu	One million BTUs. BTU is a unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit
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
PVR	PVR Partners, L.P.
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 2018 Notes, 2020 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 our Quarterly Report on Form 10-Q for the quarter ended June 30, 2013.

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)

	September 30, 2013	December 31, 2012
ASSETS		
Current Assets:		
Cash and cash equivalents	$12	$53
Trade accounts receivable, net	60	115
Accrued revenues	214	107
Related party receivables	18	8
Other current assets	63	57
Total current assets	367	340
Property, plant and equipment:		
Property, plant and equipment	4,812	4,086
Less accumulated depreciation	(570)	(400)
Property, plant and equipment, net	4,242	3,686
Other Assets:		
Investment in unconsolidated affiliates	2,081	2,214
Other, net of accumulated amortization of debt issuance costs of $22 and $17	58	43
Total other assets	2,139	2,257
Intangible assets, net of accumulated amortization of $99 and $77	690	712
Goodwill	1,128	1,128
TOTAL ASSETS	$8,566	$8,123
LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Drafts payable	$17	$10
Trade accounts payable	134	122
Accrued cost of gas and liquids	163	133
Related party payables	57	95
Accrued interest	52	30
Other current liabilities	45	82
Deferred revenues	15	17
Total current liabilities	483	489
Long-term derivative liabilities	23	25
Other long-term liabilities	38	39
Long-term debt, net	2,976	2,157
Commitments and contingencies		
Series A preferred units, redemption amounts of $37 and $85	32	73
Partners' capital and noncontrolling interest:		
Common units	3,990	3,207
Class F common units	145	—
General partner interest	783	326
Predecessor equity	—	1,733
Accumulated other comprehensive loss	—	(3)

Total partners’ capital	4,918	5,263
Noncontrolling interest	96	77
Total partners’ capital and noncontrolling interest	5,014	5,340
TOTAL LIABILITIES AND PARTNERS’ CAPITAL AND NONCONTROLLING INTEREST	$8,566	$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 September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
REVENUES				
Gas sales, including related party amounts of $22, $14, $56 and $29	$213	$141	$600	$330
NGL sales, including related party amounts of $11, $—, $23 and $24	286	267	766	709
Gathering, transportation and other fees, including related party amounts of $6, $9, $20 and $23	147	101	405	297
Net realized and unrealized (loss) gain from derivatives	(10)	1	—	20
Other	29	17	73	57
Total revenues	665	527	1,844	1,413
OPERATING COSTS AND EXPENSES				
Cost of sales, including related party amounts of $8, $12, $35 and $25	477	369	1,309	959
Operation and maintenance, including related party amounts of $—, $2, $— and $21	78	61	220	159
General and administrative, including related party amounts of $2, $4, $9 and $13	13	21	64	78
(Gain) loss on asset sales, net	(1)	—	1	2
Depreciation and amortization	74	71	207	193
Total operating costs and expenses	641	522	1,801	1,391
OPERATING INCOME	24	5	43	22
Income from unconsolidated affiliates	37	21	103	87
Interest expense, net	(41)	(29)	(119)	(86)
Loss on debt refinancing, net	—	—	(7)	(8)
Other income and deductions, net	24	1	3	26
INCOME (LOSS) BEFORE INCOME TAXES	44	(2)	23	41
Income tax expense (benefit)	2	(1)	(1)	(1)
NET INCOME (LOSS)	$42	$(1)	$24	$42
Net income attributable to noncontrolling interest	(3)	(1)	(4)	(2)
NET INCOME (LOSS) ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$39	$(2)	$20	$40
Amounts attributable to Series A preferred units	1	2	5	7
General partner’s interest, including IDRs	3	2	8	7
Beneficial conversion feature for Class F units	2	—	3	—
Pre-acquisition loss from SUGS allocated to predecessor equity	—	—	(36)	(15)
Limited partners’ interest in net income (loss)	$33	$(6)	$40	$41
Basic and diluted net income (loss) per common unit:				
Amount allocated to common units	$33	$(6)	$40	$41
Weighted average number of common units outstanding	209,559,854	170,264,621	191,334,032	166,368,178

Basic income (loss) per common unit	$0.16	$(0.04)	$0.21	$0.25
Diluted income (loss) per common unit	$0.05	$(0.04)	$0.21	$0.22
Distributions per common unit	$0.47	$0.46	$1.395	$1.38
Amount allocated to Class F units due to beneficial conversion feature	$2	$—	$3	$—
Total number of Class F units outstanding	6,274,483	—	6,274,483	—
Income per Class F unit due to beneficial conversion feature	$0.27	$—	$0.45	$—

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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Net income (loss)	$42	$(1)	$24	$42
Other comprehensive income (loss):				
Net cash flow hedge amounts reclassified to earnings	—	(6)	—	(6)
Change in fair value of cash flow hedges	—	(6)	—	5
Total other comprehensive loss	—	(12)	—	(1)
Comprehensive income (loss)	42	(13)	24	41
Comprehensive income attributable to noncontrolling interest	3	1	4	2
Comprehensive income (loss) attributable to Regency Energy Partners LP	$39	$(14)	$20	$39

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)

	Nine Months Ended September 30,	
	2013	2012
OPERATING ACTIVITIES:		
Net income	$24	$42
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	211	197
Income from unconsolidated affiliates	(103)	(87)
Derivative valuation changes	3	(11)
Loss on asset sales, net	1	2
Unit-based compensation expenses	5	3
Cash flow changes in current assets and liabilities:		
Trade accounts receivable, accrued revenues and related party receivables	(73)	9
Other current assets and other current liabilities	(26)	53
Trade accounts payable, accrued cost of gas and liquids, related party payables and deferred revenues	103	(33)
Distributions of earnings received from unconsolidated affiliates	108	92
Cash flow changes in other assets and liabilities	128	(11)
Net cash flows provided by operating activities	381	256
INVESTING ACTIVITIES:		
Capital expenditures	(762)	(380)
Capital contributions to unconsolidated affiliates	(125)	(273)
Distributions in excess of earnings of unconsolidated affiliates	232	50
Acquisitions, net of cash received	(463)	—
Proceeds from asset sales	13	22
Net cash flows used in investing activities	(1,105)	(581)
FINANCING ACTIVITIES:		
Borrowings (repayments) under revolving credit facility, net	(15)	363
Proceeds from issuances of senior notes	1,000	—
Redemptions of senior notes	(163)	(88)
Debt issuance costs	(24)	(1)
Drafts payable	8	(6)
Partner distributions and distributions on unvested unit awards	(282)	(240)
Common unit offering, net of issuance costs	—	297
Common units issued under equity distribution program, net of costs	149	15
Distributions to Series A preferred units	(5)	(6)
Contributions from noncontrolling interest	15	24
Contributions from previous parent	—	2
Net cash flows provided by financing activities	683	360
Net change in cash and cash equivalents	(41)	35
Cash and cash equivalents at beginning of period	53	1
Cash and cash equivalents at end of period	$12	$36

Supplemental cash flow information:

Accrued capital expenditures	$70	$29
Accrued capital contribution to unconsolidated affiliate	$—	$13
Issuance of Class F and common units in connection with SUGS acquisition	$961	$—

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	—	—	1,925	(1,928)	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	—	—	(504)	231	—	—	(273)
Common units issued under equity distribution program, net of costs	149	—	—	—	—	—	149
Conversion of Series A Preferred Units for common units	41	—	—	—	—	—	41
Unit-based compensation expenses	5	—	—	—	—	—	5
Partner distributions	(269)	—	(11)	—	—	—	(280)
Distributions on unvested unit awards	(2)	—	—	—	—	—	(2)
Contributions from noncontrolling interest	—	—	—	—	—	15	15
Net income (loss)	45	3	8	(36)	—	4	24
Distributions to Series A Preferred Units	(5)	—	—	—	—	—	(5)
Balance - September 30, 2013	$3,990	$145	$783	$ —	$—	$ 96	$5,014

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(a)(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.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013 (1)	2012
Revenues:				
Partnership	$665	$313	$1,576	$983
SUGS	—	214	268	430
Combined	$665	$527	$1,844	$1,413
Net income (loss):				
Partnership	$42	$(1)	$60	$57
SUGS	—	—	(36)	(15)
Combined	$42	$(1)	$24	$42

(1) The SUGS Acquisition closed on April 30, 2013. Therefore, amounts attributable to SUGS only include four months of activity for the nine months ended September 30, 2013.

PVR Acquisition. On October 10, 2013, the Partnership announced that it entered into a merger agreement with PVR ("PVR Acquisition") pursuant to which, the Partnership intends to propose to acquire PVR. This acquisition will be a unit-for-unit transaction plus a one-time $40 million cash payment to PVR unitholders which represented total consideration of $5.6 billion, including the assumption of net debt of $1.8 billion. The holders of PVR common units, PVR Class B Units and PVR Special Units ("PVR Unit(s)") will receive 1.02 Partnership common units in exchange for each PVR Unit held on the applicable record date. The transaction is subject to the approval of PVR's unitholders, Hart-Scott-Rodino Antitrust Improvements Act and other customary closing conditions.

The PVR Acquisition will enhance the Partnership's geographic diversity with a strategic presence in the Marcellus and Utica shales in the Appalachian Basin and the Granite Wash shale in the Mid-Continent region.

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 are recognized in the accompanying consolidated balance sheet at their fair value. On the date the derivative contract is entered into, SUGS designated the derivative as 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). 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. 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 upon acquisition by the Partnership.

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

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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 September 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 $21 million and $23 million as of September 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 September 30, 2013 and December 31, 2012. The Partnership also recognized deferred income tax benefit of $5 million offset by a $4 million state deferred tax expense for the nine months ended September 30, 2013.

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.

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Units Activity. The change in common and Class F units during the nine months ended September 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	35,615	—
Issuance of common units under the Equity Distribution Agreement	5,712,138	—
Issuance of common units in exchange for conversion of Series A preferred units	2,629,223	—
Issuance of common units and Class F common units in connection with SUGS Acquisition	31,372,419 (1)	6,274,483 (2)
Balance - September 30, 2013	210,700,852	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 nine months ended September 30, 2013, the Partnership received net proceeds of $149 million from units issued pursuant to an Equity Distribution Agreement with Citi, which were used for general partnership purposes. As of September 30, 2013, $34 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
September 30, 2013	November 4, 2013	November 14, 2013	$0.470

3. Income (Loss) 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 nine months ended September 30, 2013 and 2012:

	Three Months Ended September 30,					
	2013			2012		
	Income (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
Basic income (loss) per unit						
Amounts allocated to common units	$33	209,559,854	$0.16	$(6)	170,264,621	$(0.04)
Effect of Dilutive Securities:						
Common unit options	—	32,489		—	—	
Phantom units *	—	435,606		—	—	
Series A preferred units	(23)	2,047,571		—	—	
Diluted income (loss) per unit	$10	212,075,520	$0.05	$(6)	170,264,621	$(0.04)

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	Nine Months Ended September 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	$40	191,334,032	$0.21	$41	166,368,178	$0.25
Effect of Dilutive Securities:						
Common unit options	—	23,931		—	13,113	
Phantom units *	—	351,811		—	320,452	
Series A preferred units	—	—		(3)	4,651,884	
Diluted income per unit	$40	191,709,774	$0.21	$38	171,353,627	$0.22

* 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:

	Nine Months Ended September 30, 2013	Three Months Ended September 30, 2012
Common unit options	—	9,147
Phantom units	—	313,378
Series A preferred units	2,047,571	4,651,884

4. Investment in Unconsolidated Affiliates

As of September 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 September 30, 2013 and December 31, 2012 is as follows:

	September 30, 2013	December 31, 2012
HPC	$448	$650
MEP	556	581
Lone Star	1,040	948
Ranch JV	36	35
Grey Ranch	1	—
	$2,081	$2,214

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

	Three Months Ended September 30, 2013			
	HPC (1)	MEP	Lone Star	Ranch JV
Contributions to unconsolidated affiliates	$—	$—	$51	$1
Distributions from unconsolidated affiliates	(196)	(18)	(16)	(1)
Share of earnings of unconsolidated affiliates’ net income	9	11	18	—
Amortization of excess fair value of investment	(1)	—	—	—

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	Three Months Ended September 30, 2012			
	HPC	MEP	Lone Star	Ranch JV
Contributions to unconsolidated affiliates	$—	$—	$78	$10
Distributions from unconsolidated affiliates	(16)	(18)	(21)	—
Share of earnings of unconsolidated affiliates' net income	3	10	9	—
Amortization of excess fair value of investment	(1)	—	—	—

	Nine Months Ended September 30, 2013			
	HPC [1]	MEP	Lone Star	Ranch JV
Contributions to unconsolidated affiliates	$—	$—	$100	$2
Distributions from unconsolidated affiliates	(226)	(56)	(56)	(1)
Share of earnings of unconsolidated affiliates' net income	28	31	48	—
Amortization of excess fair value of investment	(4)	—	—	—

	Nine Months Ended September 30, 2012			
	HPC	MEP	Lone Star	Ranch JV
Contributions to unconsolidated affiliates	$—	$—	$253	$33
Distributions from unconsolidated affiliates	(46)	(56)	(39)	—
Share of earnings of unconsolidated affiliates' net income	28	31	32	—
Amortization of excess fair value of investment	(4)	—	—	—

[1] The Partnership received a non-recurring return of capital of $185 million from HPC in September 2013. HPC entered into a $500 million 5-year revolving credit facility in September 2013. Concurrent with the closing of this facility, HPC borrowed $370 million to fund a non-recurring return of capital to the partners. The Partnership pledged its 49.99% equity interest in Regency Intrastate Gas LP. The amounts outstanding under this facility was $445 million as of September 30, 2013. The Partnership's contingent obligations with respect to the outstanding borrowings under this facility was $222 million at September 30, 2013.

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

	Three Months Ended September 30, 2013			
	HPC	MEP	Lone Star	Ranch JV
Total revenues	$38	$66	$537	$4
Operating income	19	34	61	1
Net income	18	21	61	1

	Three Months Ended September 30, 2012			
	HPC	MEP	Lone Star	Ranch JV
Total revenues	$42	$65	$165	$—
Operating income (loss)	21	33	31	(1)
Net income (loss)	6	21	31	(1)

	Nine Months Ended September 30, 2013			
	HPC	MEP	Lone Star	Ranch JV
Total revenues	$116	$194	$1,320	$10
Operating income	58	101	162	2
Net income	56	63	160	2

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	Nine Months Ended September 30, 2012			
	HPC	MEP	Lone Star	Ranch JV
Total revenues	$130	$196	$490	$—
Operating income (loss)	71	101	110	(1)
Net income (loss)	55	63	110	(1)

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 AOCI 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 September 30, 2013, the Partnership had $176 million of outstanding borrowings exposed to variable interest rate risk.

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 September 30, 2013 would be $7 million, which would be reduced by $2 million, due to the netting features. 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.

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

	Assets		Liabilities	
	September 30, 2013	December 31, 2012	September 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	$6	$4	$5	$1
Long-term amounts				
Commodity contracts	1	1	—	—
Embedded derivatives in Series A preferred units	—	—	23	25
Total derivatives	$7	$5	$28	$31

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

		Three Months Ended September 30,	
		2013	2012
Derivatives in cash flow hedging relationships:		Change in Value Recognized in AOCI on Derivatives (Effective Portion)	
Commodity derivatives		$—	$(6)
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) Recognized in Income on Derivatives	
Commodity derivatives	Revenues	$(10)	$(5)
Embedded derivatives in Series A preferred units	Other income & deductions, net	24	2
		$14	$(3)

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		Nine Months Ended September 30, 2013	2012
Derivatives in cash flow hedging relationships:		Change in Value Recognized in AOCI on Derivatives (Effective Portion)	
Commodity derivatives		$—	$5
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	$—	$12
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	$—	$14
Embedded derivatives in Series A preferred units	Other income & deductions, net	2	10
		$2	$24

6. Long-term Debt

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

	September 30, 2013	December 31, 2012
Senior notes	$2,800	$1,965
Revolving loans	176	192
Total	2,976	2,157
Less: current portion	—	—
Long-term debt	$2,976	$2,157
Availability under revolving credit facility:		
Total credit facility limit	$1,200	$1,150
Revolving loans	(176)	(192)
Letters of credit	(15)	(12)
Total available	$1,009	$946

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

Years Ending December 31,	Amount
2013 (remainder)	$—
2014	—
2015	—
2016	—
2017	—
Thereafter	2,976
Total	$2,976

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Revolving Credit Facility

The weighted average interest rate on the total amounts outstanding under the Partnership's revolving credit facility was 2.19% as of September 30, 2013.

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. As of September 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 September 30, 2013. In addition, the Partnership capitalized $7 million of loan fees which is being amortized over the remaining term.

4.5% Senior Notes Due 2023

In April 2013, in conjunction with financing 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 mature on November 1, 2023.

At any time prior to August 1, 2023, the Partnership 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, the Partnership may redeem some or all of the 2023 4.5% Notes at a price equal to 100% plus accrued interest.

9.375% Senior Notes Due 2016

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.

5.75% Senior Notes Due 2020

In September 2013, the Partnership and Finance Corp. issued $400 million senior notes due September 1, 2020 (the "2020 Notes"). The 2020 Notes bear interest at 5.75% payable semi-annually on March 1 and September 1, commencing March 1, 2014, and mature on September 1, 2020.

At any time prior to June 1, 2020, the Partnership may redeem some or all of the 2020 Notes at a price equal to 100% of the principal amount plus a make-whole premium and accrued interest. On or after June 1, 2020, the Partnership may redeem some or all of the 2020 Notes at a price equal to 100% plus accrued interest.

Covenants

Upon a change of control, as defined in the indentures, followed by a ratings decline within 90 days, each holder of the 2023 4.5% Notes and the 2020 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.

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The 2023 4.5% Notes and the 2020 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 our equity interests;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets or consolidate or merge with or into other companies.

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

If the 2023 4.5% Notes and the 2020 Notes achieve investment grade ratings by both Moody's and S&P and no default or event of default has occurred and is continuing, we will no longer be subject to many of the foregoing covenants.

The 2023 4.5% Notes and the 2020 Notes are jointly and severally guaranteed by all of our consolidated subsidiaries, other than Finance Corp. and a minor subsidiary. The senior notes and 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.

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 minor subsidiary, 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.

Four putative class action lawsuits challenging the merger have been filed, two in the Court of Chancery of the State of Delaware: (i) David Naiditch v. PVR Partners, L.P., et al. (Case No. 9015-VCL); and (ii) Robert P. Frutkin v. Edward B. Cloues II, et al. (Case No. 9020-VCL), and two in the Court of Common Pleas for Delaware County, Pennsylvania: (i) Charles Monatt v. PVR Partners, LP, et al. (Case No. 2013-10606); and [(ii) Steven Keene v. James L. Gardner, et al. (Case No. 2013-010723)]. All of the cases name PVR, PVR GP and the current directors of PVR GP, as well as the Partnership, the General Partner and RVP LLC, a subsidiary of the Partnership (collectively, the "Regency Defendants"), as defendants. Each of the lawsuits has been brought by a purported unitholder of PVR, both individually and on behalf of a putative class consisting of public unitholders of PVR. The lawsuits generally allege, among other things, that the directors of PVR GP breached their fiduciary duties to unitholders of PVR by agreeing to a transaction with inadequate consideration and unfair terms and pursuant to an inadequate process. The lawsuits allege further that PVR GP and the Regency Defendants aided and abetted the directors of PVR GP in the alleged breach of their fiduciary duties. The Naiditch and Monatt lawsuits allege further that PVR also aided and abetted the directors of PVR GP in the alleged breach of their fiduciary duties. The lawsuits seek, in general, (i) injunctive relief enjoining the transactions contemplated by the merger agreement, (ii) in the event the merger is consummated, rescission or an award of rescissory damages, (iii) an award of plaintiffs' costs, including reasonable attorneys' and experts' fees, (iv) the accounting by the defendants to plaintiffs for all damages caused by the defendants, and (v) such further relief as the court deems just and proper. Similar actions may be filed in the future.

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 at September 30, 2013 and December 31, 2012. Except as described above, the Partnership does not have any material environmental remediation matters assessed as reasonably possible that would require disclosure in the financial statements.

	September 30, 2013	December 31, 2012
Current	$2	$5
Noncurrent	7	7
Total environmental liabilities	$9	$12

The Partnership recorded expenditures related to environmental remediation of $4 million for the nine months ended September 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 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. Hearings on the COs were delayed until March 2014 to allow the parties to pursue substantive settlement discussions. The Partnership has meritorious defenses to the NMED claims and can offer significant mitigating factors to the claimed violations. The Partnership has recorded a liability of less than $1 million related to the claims and will continue to assess its potential exposure to the allegations as the matters progress.

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

In July 2013, certain holders of Series A Preferred Units exercised their right to convert 2,459,017 Series A Preferred Units into common units. Concurrent with this transaction, the Partnership recognized a $26 million gain in other income and deductions, net, related to the embedded derivative and reclassified $41 million from the Series A Preferred Units into common units. As of September 30, 2013, the remaining Series A Preferred Units were convertible into 2,047,571 common units, and if outstanding, are mandatorily redeemable on September 2, 2029 for $35 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 into 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 nine months ended September 30, 2013:

	Units	Amount
Outstanding at beginning of period	4,371,586	$73

Series A Preferred Units converted into common units	(2,459,017)	(41)
Accretion to redemption value	N/A	—
Outstanding at end of period	1,912,569	$32 *

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* This amount will be accreted to $35 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.

9. Related Party Transactions

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

	September 30, 2013	December 31, 2012
Related party receivables		
HPC	$1	$1
ETE and its subsidiaries	17	5
Ranch JV	—	2
Total related party receivables	$18	$8
Related party payables		
HPC	$1	$1
ETE and its subsidiaries	56	94
Total related party payables	$57	$95

Transactions with ETE and its subsidiaries. Under the service agreement with Services Co., the Partnership paid Services Co.'s direct expenses for services performed, plus an annual fee of $10 million, and received 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 describes the services that ETC will provide in the future.

The Partnership incurred total service fees related to the agreements described above from ETE and its subsidiaries of $2 million and $4 million for the three months ended September 30, 2013 and 2012, respectively, and $9 million and $13 million for the nine months ended September 30, 2013 and 2012, respectively.

In conjunction with distributions by the Partnership to the limited and general partner interests, ETE received cash distributions of $16 million for each of the three months ended September 30, 2013 and 2012, and $47 million and $46 million for the nine months ended September 30, 2013 and 2012, respectively.

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 recorded $5 million for NGL sales to Lone Star under a short-term agreement during the three months ended September 30, 2013, and is included in the $17 million related party receivable from ETE and its subsidiaries. The Partnership's Contract Services segment provides contract compression and treating services to subsidiaries of ETE and records revenue in gathering, transportation and other fees. The Partnership's Contract Services segment purchased compression equipment from a subsidiary of ETE for $39 million and $76 million for the three and nine months ended September 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 trademarks, trade names and service marks by SUGS. These administrative services are no longer being provided subsequent to the SUGS Acquisition.

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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 September 30, 2013 and 2012, respectively, and $14 million each of the nine months ended September 30, 2013 and 2012, 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 nine months ended September 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 ELG and 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 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.

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Results for each segment are shown below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
External Revenues				
Gathering and Processing	$603	$475	$1,671	$1,262
Natural Gas Transportation	—	—	—	—
NGL Services	—	—	—	—
Contract Services	58	47	159	137
Corporate	4	5	14	14
Eliminations	—	—	—	—
Total	$665	$527	$1,844	$1,413
Intersegment Revenues				
Gathering and Processing	$—	$—	$—	$—
Natural Gas Transportation	—	—	—	—
NGL Services	—	—	—	—
Contract Services	4	5	11	15
Corporate	—	—	—	—
Eliminations	(4)	(5)	(11)	(15)
Total	$—	$—	$—	$—
Segment Margin				
Gathering and Processing	$136	$110	$383	$314
Natural Gas Transportation	—	—	—	1
NGL Services	—	—	—	—
Contract Services	52	48	149	140
Corporate	4	5	14	14
Eliminations	(4)	(5)	(11)	(15)
Total	$188	$158	$535	$454
Operation and Maintenance				
Gathering and Processing	$63	$50	$177	$125
Natural Gas Transportation	—	—	—	—
NGL Services	—	—	—	—
Contract Services	19	16	53	49
Corporate	—	—	1	—
Eliminations	(4)	(5)	(11)	(15)
Total	$78	$61	$220	$159

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Total segment margin	$188	$158	$535	$454
Operation and maintenance	(78)	(61)	(220)	(159)
General and administrative	(13)	(21)	(64)	(78)
Gain (loss) on asset sales, net	1	—	(1)	(2)
Depreciation and amortization	(74)	(71)	(207)	(193)
Income from unconsolidated affiliates	37	21	103	87
Interest expense, net	(41)	(29)	(119)	(86)
Loss on debt refinancing, net	—	—	(7)	(8)
Other income and deductions, net	24	1	3	26 *
Income (loss) before income taxes	$44	$(2)	$23	$41

* Other income and deductions, net for the nine months ended September 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	September 30, 2013	December 31, 2012
Gathering and Processing	$4,631	$4,210
Natural Gas Transportation	1,005	1,232
NGL Services	1,040	948
Contract Services	1,812	1,672
Corporate	78	61
Total	$8,566	$8,123

Investment in Unconsolidated Affiliates	September 30, 2013	December 31, 2012
Gathering and Processing	$37	$35
Natural Gas Transportation	1,004	1,231
NGL Services	1,040	948
Total	$2,081	$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 $2 million and $1 million was recorded in general and administrative expense for the three months ended September 30, 2013 and 2012, respectively, and $5 million and $3 million for the nine months ended September 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 nine months ended September 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	(45,158)	24.34
Forfeited service condition	(25,900)	23.29
Forfeited market condition	(44,397)	19.52
Outstanding at end of period	1,168,247	$ 23.41

The Partnership expects to recognize $20 million of compensation expense related to non-vested phantom units over a weighted-average period of 3.5 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 September 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	$6	$6	$—	$ 2	$ 2	$—
NGLs	1	1	—	1	1	—
Condensate	—	—	—	2	2	—
Total Assets	$7	$7	$—	$ 5	$ 5	$—
Liabilities						
Commodity Derivatives:						
Natural Gas	$1	$1	$—	$ 5	$ 5	$—
NGLs	2	2	—	1	1	—
Condensate	2	2	—	—	—	—
Embedded derivatives in Series A preferred units	23	—	23	25	—	25
Total Liabilities	$28	$5	$ 23	$ 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	September 30, 2013	
Credit Spread	6.39	%
Volatility	19.96	%

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 nine months ended September 30, 2013. There were no transfers between the fair value hierarchy levels for the nine months ended September 30, 2013.

	Embedded Derivatives in Series A Preferred Units	
Net liability balance at December 31, 2012	$25	
Change in fair value, net of gain at conversion of $26 million	(2	)
Net liability balance at September 30, 2013	$23	

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 September 30, 2013 were $2.8 billion. As of December 31, 2012, the aggregate fair value and carrying amount of the Senior Notes was $2.1 billion and $2 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 Form 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 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.

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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(a)(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.

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 beginning March 26, 2012 (the date upon which common control began).

PVR Acquisition. On October 10, 2013, we announced that we entered into a merger agreement with PVR ("PVR Acquisition") pursuant to which, we intend to propose to acquire PVR. This acquisition will be a unit-for-unit transaction plus a one-time $40 million cash payment to PVR unitholders which represented total consideration of $5.6 billion, including the assumption of net debt of $1.8 billion. The holders of PVR common units, PVR Class B Units and PVR Special Units ("PVR Unit(s)") will receive 1.02 Partnership common units in exchange for each PVR Unit held on the applicable record date. The transaction is subject to the approval of PVR's unitholders, Hart-Scott-Rodino Antitrust Improvements Act and other customary closing conditions.

The PVR Acquisition will enhance our geographic diversity with a strategic presence in the Marcellus and Utica shales in the Appalachian Basin and the Granite Wash shale in the Mid-Continent region.

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

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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.

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

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- 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.

The following table presents a reconciliation of EBITDA and adjusted EBITDA to net cash flows provided by operating activities and to net income for the Partnership:

	Nine Months Ended September 30,			
Reconciliation of "Adjusted EBITDA" to net cash flows provided by operating activities and net income	2013		2012	
Net cash flows provided by operating activities	$381		$256	
Add (deduct):				
Depreciation and amortization, including debt issuance cost amortization and bond premium write-off and amortization	(211	)	(197	)
Income from unconsolidated affiliates	103		87	
Derivative valuation change	(3	)	11	
Loss on asset sales, net	(1	)	(2	)
Unit-based compensation expenses	(5	)	(3	)
Trade accounts receivable, accrued revenues and related party receivables	73		(9	)
Other current assets and other current liabilities	26		(53	)
Trade accounts payable, accrued cost of gas and liquids, related party payables and deferred revenues	(103	)	33	
Distributions of earnings received from unconsolidated affiliates	(108	)	(92	)
Cash flow changes in other assets and liabilities	(128	)	11	
Net income	24		42	
Add (deduct):				
Interest expense, net	119		86	
Depreciation and amortization expense	207		193	
Income tax benefit	(1	)	(1	)
EBITDA	349		320	
Add (deduct):				
Partnership's interest in unconsolidated affiliates' adjusted EBITDA	188		171	
Income from unconsolidated affiliates	(103	)	(87	)
Non-cash gain from commodity and embedded derivatives	—		(17	)
Loss on debt extinguishment	7		8	
Other expense, net	5		3	
Adjusted EBITDA	$446		$398	

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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 nine months ended September 30, 2013 and 2012:

	Nine Months Ended September 30, 2013				
	HPC	MEP	Lone Star	Ranch JV	Total
Net income	$56	$63	$160	$2	
Add:					
Depreciation and amortization	27	52	61	4	
Interest expense, net	2	38	—	—	
Other expenses, net	—	—	2	—	
Adjusted EBITDA	85	153	223	6	
Ownership interest	49.99 %	50 %	30 %	33.33 %	
Partnership's interest in adjusted EBITDA	$42	$77	$67	$2	$188

	Nine Months Ended September 30, 2012				
	HPC	MEP	Lone Star	Ranch JV	Total
Net income (loss)	$55	$63	$110	$(1)	
Add:					
Depreciation and amortization	28	52	38	—	
Impairment of property, plant, and equipment	14	—	—	—	
Interest expense, net	2	38	—	—	
Other expenses, net	1	—	—	—	
Adjusted EBITDA	100	153	148	(1)	
Ownership interest	49.99 %	50 %	30 %	33.33 %	
Partnership's interest in adjusted EBITDA	$50	$77	$44	$—	$171

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Net income (loss)	$42	$(1		