Regency Energy Partners LP
Form 10-Q
August 07, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)

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

For the quarterly period ended June 30, 2014
or

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

Commission file number 1-35262
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 397,703,627 common units and 6,274,483 Class F units outstanding as of August 1, 2014.

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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)
Aqua - PVR	Aqua - PVR Water Services, LLC
ARO	Asset Retirement Obligation
Barclays	Barclays Capital Inc.
Bbls	Barrels
bps	Basis points
Citi	Citigroup Global Markets Inc.
Coal Handling	Coal Handling Solutions LLC
Eagle Rock	Eagle Rock Energy Partners, L.P.
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.
ETE Common Holdings	ETE Common Holdings, LLC, a wholly-owned subsidiary of ETE
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	Grey Ranch Plant LP, a former joint venture between SUGS and a subsidiary of SandRidge Energy, Inc.
Gulf States	Gulf States Transmission LLC, a wholly-owned subsidiary of the Partnership
Holdco	ETP Holdco Corporation
Hoover	Hoover Energy Partners, LP
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	Panhandle Eastern Pipe Line Company, LP
PEPL Holdings	PEPL Holdings, LLC, a former wholly-owned subsidiary of Southern Union that merged into PEPL
PVR	PVR Partners, L.P.

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Name	Definition or Description
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, 2018 PVR Notes, 2020 Notes, 2020 PVR Notes, 2021 Notes, 2021 PVR Notes, 2022 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. 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," "expect," "continue," "estimate," "goal," "forecast," "may" or similar expression forward-looking statements. Although we believe our forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, we cannot give assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions including without limitation the following:

- volatility in the price of oil, natural gas, condensate, NGLs and coal;
- unexpected difficulties in integrating any significant acquisitions into our operations, including the PVR Acquisition, the Eagle Rock Midstream Acquisition and the Hoover Acquisition;
- 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 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 or enforcement practices impacting the midstream sector of the natural gas industry, oil industry and the coal mining industry, including those that relate to climate change and environmental protection and safety, including with respect to emissions levels applicable to coal-burning power generators and permissible levels of mining runoff;
- the adoption of new laws, or the promulgation of new regulations, at the federal, state or local level that promote use and development of renewable energy or limit use or development of fossil fuels;
- weather and other natural phenomena;
- industry changes including the impact of consolidation and changes in competition;
- regulation of transportation rates on our natural gas, NGL, and oil 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;
- the effect of accounting pronouncements issued periodically by accounting standard setting boards;
- the extent to which the amount and quality of actual production of our coal differs from estimated recoverable coal reserves;
- the experience and financial condition of our coal lessees, including our lessees' ability to satisfy their royalty, environmental, reclamation and other obligations to us and others;
- operating risks, including unanticipated geological problems, incidental to our Gathering and Processing segment and Natural Resources segment;
- the ability of our lessees to produce sufficient quantities of coal on an economic basis from our reserves and obtain favorable contracts for such production;
- delays in anticipated start-up dates of new development in our Gathering and Processing segment and our lessees' mining operations and related coal infrastructure projects, including the timing of receipt of necessary governmental permits by us or our lessees; and
- uncertainties relating to the effects of regulatory guidance on permitting under the Clean Water Act and the outcome of current and future litigation regarding mine permitting.

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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, 2013 Annual Report on Form 10-K and in Part II — Other Information — Item 1A. Risk Factors in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2014.

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

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PART I – FINANCIAL INFORMATION
Item 1. Financial Statements
Regency Energy Partners LP
Condensed Consolidated Balance Sheets
(in millions)
(unaudited)

	June 30, 2014	December 31, 2013
ASSETS		
Current Assets:		
Cash and cash equivalents	$50	$19
Trade accounts receivable, net	449	292
Related party receivables	19	28
Inventories	60	42
Other current assets	14	19
Total current assets	592	400
Property, plant and equipment	8,256	5,050
Less accumulated depreciation and depletion	(840)	(632)
Property, plant and equipment, net	7,416	4,418
Investment in unconsolidated affiliates	2,378	2,097
Other, net of accumulated amortization of debt issuance costs of $28 and $24	87	57
Intangible assets, net of accumulated amortization of $150 and $107	3,500	682
Goodwill	1,486	1,128
TOTAL ASSETS	$15,459	$8,782
LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Drafts payable	$—	$26
Trade accounts payable	353	291
Related party payables	215	69
Accrued interest	65	38
Other current liabilities	97	51
Total current liabilities	730	475
Long-term derivative liabilities	29	19
Other long-term liabilities	59	30
Long-term debt, net	5,490	3,310
Commitments and contingencies		
Series A Preferred Units, redemption amounts of $38 and $38	32	32
Partners' capital and noncontrolling interest:		
Common units	8,079	3,886
Class F units	150	146
General partner interest	783	782
Total partners' capital	9,012	4,814
Noncontrolling interest	107	102
Total partners' capital and noncontrolling interest	9,119	4,916
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$15,459	$8,782

See accompanying notes to condensed consolidated financial statements

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

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
REVENUES				
Gas sales, including related party amounts of $22, $26, $35 and $34	$475	$220	$810	$387
NGL sales, including related party amounts of $57, $11, $107 and $12	422	245	753	480
Gathering, transportation and other fees, including related party amounts of $7, $6, $13 and $14	227	131	399	258
Net realized and unrealized (loss) gain from derivatives	(5)	14	(18)	11
Other	59	29	97	43
Total revenues	1,178	639	2,041	1,179
OPERATING COSTS AND EXPENSES				
Cost of sales, including related party amounts of $16, $23, $26 and $27	828	445	1,466	832
Operation and maintenance	93	73	171	142
General and administrative	54	18	87	51
Loss (gain) on asset sales, net	—	1	(2)	2
Depreciation, depletion and amortization	168	68	262	133
Total operating costs and expenses	1,143	605	1,984	1,160
OPERATING INCOME	35	34	57	19
Income from unconsolidated affiliates	47	31	90	66
Interest expense, net	(78)	(41)	(134)	(78)
Loss on debt refinancing, net	—	(7)	—	(7)
Other income and deductions, net	(7)	(7)	(5)	(21)
(LOSS) INCOME BEFORE INCOME TAXES	(3)	10	8	(21)
Income tax expense (benefit)	1	(1)	—	(3)
NET (LOSS) INCOME	$(4)	$11	$8	$(18)
Net income attributable to noncontrolling interest	(4)	(1)	(7)	(1)
NET (LOSS) INCOME ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$(8)	$10	$1	$(19)
Amounts attributable to Series A Preferred Units	1	2	2	4
General partner's interest, including IDRs	7	3	12	5
Beneficial conversion feature for Class F units	2	1	4	1
Pre-acquisition loss from SUGS allocated to predecessor equity	—	(9)	—	(33)
Limited partners' interest in net (loss) income	$(18)	$13	$(17)	$4
Basic and diluted net (loss) income per common unit:				
Amount allocated to common units	$(18)	$13	$(17)	$4
Weighted average number of common units outstanding	361,071,005	193,065,183	293,931,615	182,070,077
Basic (loss) income per common unit	$(0.05)	$0.07	$(0.06)	$0.02
Diluted (loss) income per common unit	$(0.05)	$0.07	$(0.06)	$0.02
Distributions per common unit	$0.490	$0.465	$0.970	$0.925
Amount allocated to Class F units due to beneficial conversion feature	$2	$1	$4	$1

Total number of Class F units outstanding	6,274,483	6,274,483	6,274,483	6,274,483
Income per Class F unit due to beneficial conversion feature	$0.27	$0.18	$0.54	$0.18

See accompanying notes to condensed consolidated financial statements

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net (loss) income	$(4)	$11	$8	$(18)
Other comprehensive income (loss)	—	—	—	—
Total other comprehensive income (loss)	—	—	—	—
Comprehensive (loss) income	(4)	11	8	(18)
Comprehensive income attributable to noncontrolling interest	4	1	7	1
Comprehensive (loss) income attributable to Regency Energy Partners LP	$(8)	$10	$1	$(19)

See accompanying notes to condensed consolidated financial statements

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

	Six Months Ended June 30,	
	2014	2013
OPERATING ACTIVITIES:		
Net income (loss)	$8	$(18)
Reconciliation of net income (loss) to net cash flows provided by operating activities:		
Depreciation, depletion and amortization, including debt issuance cost amortization and bond premium write-off and amortization	264	137
Income from unconsolidated affiliates	(90)	(66)
Derivative valuation changes	13	17
Loss (gain) on asset sales, net	(2)	2
Unit-based compensation expenses	5	3
Cash flow changes in current assets and liabilities:		
Trade accounts receivable and related party receivables	(17)	(41)
Other current assets and other current liabilities	26	(51)
Trade accounts payable and related party payables	(36)	10
Distributions of earnings received from unconsolidated affiliates	96	71
Cash flow changes in other assets and liabilities	10	131
Net cash flows provided by operating activities	277	195
INVESTING ACTIVITIES:		
Capital expenditures	(401)	(472)
Capital contributions to unconsolidated affiliates	(83)	(72)
Distributions in excess of earnings of unconsolidated affiliates	20	37
Acquisitions, net of cash received	(212)	(463)
Proceeds from asset sales	6	12
Net cash flows used in investing activities	(670)	(958)
FINANCING ACTIVITIES:		
(Repayments) borrowings under revolving credit facility, net	(275)	343
Proceeds from issuances of senior notes	884	600
Redemptions of senior notes	(313)	(163)
Debt issuance costs	(22)	(17)
Drafts payable	(25)	7
Partner distributions and distributions on unvested unit awards	(286)	(179)
Common unit offering, net of issuance costs	400	128
Common units issued under equity distribution program, net of costs	65	—
Distributions to Series A Preferred Units	(2)	(4)
Noncontrolling interest (distributions) contributions	(2)	12
Net cash flows provided by financing activities	424	727
Net change in cash and cash equivalents	31	(36)
Cash and cash equivalents at beginning of period	19	53
Cash and cash equivalents at end of period	$50	$17
Supplemental cash flow information:		
Accrued capital expenditures	$48	$133
Accrued capital contribution to unconsolidated affiliates	175	22

Issuance of Class F and common units in connection with SUGS Acquisition	—	1,223
Interest paid, net of amounts capitalized	134	—
Issuance of common units in connection with PVR and Hoover acquisitions	4,015	—
Long-term debt assumed in PVR Acquisition	1,887	—

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 Units	General Partner Interest	Noncontrolling Interest	Total
Balance - December 31, 2013	$3,886	$146	$782	$102	$4,916
Issuance of common units under equity distribution program, net of costs	65	—	—	—	65
Issuance of common units to ETE Common Holdings	400	—	—	—	400
Issuance of common units in connection with Hoover Acquisition	109	—	—	—	109
Issuance of common units in connection with PVR Acquisition	3,906	—	—	—	3,906
Unit-based compensation expenses	5	—	—	—	5
Partner distributions and distributions on unvested unit awards	(275)	—	(11)	—	(286)
Noncontrolling interest distributions, net	—	—	—	(2)	(2)
Net (loss) income	(15)	4	12	7	8
Distributions to Series A Preferred Units	(2)	—	—	—	(2)
Balance - June 30, 2014	$8,079	$150	$783	$107	$9,119

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; the transportation, fractionation and storage of NGLs; the gathering, transportation and terminaling of oil (crude and/or condensate, a lighter oil) received from producers; and the management of coal and natural resource properties in the United States. 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 accounted for the acquisition in a manner similar to the pooling of interests method of accounting as it was a transaction between commonly controlled entities. The Partnership retrospectively adjusted its March 31, 2013 financial statements to include the operations of SUGS for periods prior to April 30, 2013. The SUGS Acquisition did not impact historical earnings per unit as pre-acquisition earnings were allocated to predecessor equity.

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

	Three Months Ended June 30, 2013	Six Months Ended June 30, 2013 [1]
Revenues:		
Partnership	$562	$911
SUGS	77	268
Combined	$639	$1,179
Net income (loss):		
Partnership	$20	$15
SUGS	(9)	(33)
Combined	$11	$(18)

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

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, 2013. 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.

Equity Method Investments. Even though there is a presumption of a controlling financial interest in Aqua - PVR (because of our 51% ownership), our partner in this joint venture has substantive participating rights and management authority that preclude us from controlling the joint venture. Therefore, it is accounted for as an equity method investment.

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Coal Royalties Revenues and Deferred Income. The Partnership recognizes coal royalties revenues on the basis of tons of coal sold by its lessees and the corresponding revenues from those sales. The Partnership does not have access to actual production and revenues information until 30 days following the month of production. Therefore, financial results include estimated revenues and accounts receivable for the month of production. The Partnership records any differences between the actual amounts ultimately received or paid and the original estimates in the period they become finalized. Most lessees must make minimum monthly or annual payments that are generally recoverable over certain time periods. These minimum payments are recorded as deferred income. If the lessee recovers a minimum payment through production, the deferred income attributable to the minimum payment is recognized as coal royalties revenues. If a lessee fails to meet its minimum production for certain pre-determined time periods, the deferred income attributable to the minimum payment is recognized as minimum rental revenues, which is a component of other revenues on our consolidated statements of operations. Other liabilities on the balance sheet also include deferred unearned income from a coal services facility lease, which is recognized as other income as it is earned.

New Accounting Pronouncement. In May 2014, the FASB issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) (“ASU 2014-09”), which clarifies the principles for recognizing revenue based on the core principle that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period, with earlier adoption not permitted. ASU 2014-09 can be adopted either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment as of the date of adoption. The Partnership is currently evaluating the impact, if any, that adopting this new accounting standard will have on our revenue recognition policies.

2. Partners’ Capital and Distributions

Beneficial Conversion Feature. The beneficial conversion feature, incurred as a result of the issuance of Class F units, is reflected in income per unit using the effective yield method over the period the Class F units are outstanding, as indicated on the statement of operations in the line item entitled “beneficial conversion feature for Class F units.” The Class F units will convert to common units on a one-for-one basis on May 8, 2015.

Equity Distribution Agreement. In June 2012, the Partnership entered into an equity distribution agreement with Citi under which the Partnership may offer and sell common units having an aggregate offering price of up to $200 million, from time to time through Citi, as sales agent for the Partnership. Sales of these units made from time to time under the equity distribution agreement were made by means of ordinary brokers’ transactions on the New York Stock Exchange at market prices, in block transactions, or as otherwise agreed upon by the Partnership and Citi. The Partnership used the net proceeds from the sale of these common units for general partnership purposes. During the six months ended June 30, 2014, the Partnership received net proceeds of $34 million from common units sold pursuant to this equity distribution agreement and no amounts remained available to be issued under this agreement and it is no longer effective.

In May 2014, the Partnership entered into an equity distribution agreement with Barclays under which the Partnership may offer and sell common units having an aggregate offering price of up to $400 million, from time to time through Barclays, as sales agent for the Partnership. Sales of these units made from time to time under the equity distribution agreement will be made by means of ordinary brokers’ transactions on the New York Stock Exchange at market prices, in block transactions, or as otherwise agreed upon by the Partnership and Barclays. The Partnership may also sell common units to Barclays as principal for its own account at a price agreed upon at the time of sale. Any sale of common units to Barclays as principal would be pursuant to the terms of a separate agreement between the Partnership and Barclays. The Partnership intends to use the net proceeds from the sale of these units for general partnership purposes. During the six months ended June 30, 2014, the Partnership received net proceeds of $31 million from common units sold pursuant to this equity distribution agreement.

Common Units Sold. In June 2014, the Partnership sold 14.4 million common units to ETE Common Holdings for proceeds of $400 million. Proceeds from the issuance were used to pay down borrowings on the Partnership's revolving credit facility, to redeem certain senior notes of the Partnership and for general partnership purposes. In July 2014, the Partnership sold 16.5 million common units to ETE Common Holdings for proceeds of $400 million, and issued 8.2 million common units to Eagle Rock in connection with the Eagle Rock Midstream Acquisition.

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Units Activity. The change in common and Class F units during the six months ended June 30, 2014 was as follows:

	Common	Class F
Balance - December 31, 2013	210,850,232	6,274,483
Issuance of common units under LTIP, net of forfeitures and tax withholding	24,808	—
Issuance of common units under the equity distribution agreements	2,374,397	—
Issuance of common units in connection with Hoover Acquisition	4,040,471	—
Issuance of common units in connection with PVR Acquisition	140,388,382	—
Issuance of common units to ETE Common Holdings	14,398,848	—
Balance - June 30, 2014	372,077,138	6,274,483

Quarterly Distributions of Available Cash. Following are distributions declared by the Partnership subsequent to December 31, 2013:

Quarter Ended	Record Date	Payment Date	Cash Distributions (per common unit)
December 31, 2013	February 7, 2014	February 14, 2014	$0.475
March 31, 2014	May 8, 2014	May 15, 2014	$0.480
June 30, 2014	August 7, 2014	August 14, 2014	$0.490

3. (Loss) Income per Common Unit

The following tables provide a reconciliation of the numerator and denominator of the basic and diluted earnings per common unit computations for the three and six months ended June 30, 2014 and 2013:

	Three Months Ended June 30,					
	2014			2013		
	Loss (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
Basic (loss) income per unit						
Amount allocated to common units	$(18)	361,071,005	$(0.05)	$13	193,065,183	$0.07
Effect of Dilutive Securities:						
Common unit options	—	—		—	24,365	
Phantom units	—	—		—	331,462	
Diluted (loss) income per unit	$(18)	361,071,005	$(0.05)	$13	193,421,010	$0.07

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	Six Months Ended June 30,					
	2014			2013		
	Loss (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
Basic (loss) income per unit						
Amount allocated to common units	$(17)	293,931,615	$(0.06)	$4	182,070,077	$0.02
Effect of Dilutive Securities:						
Common unit options	—	—		—	19,035	
Phantom units	—	—		—	303,218	
Diluted (loss) income per unit	$(17)	293,931,615	$(0.06)	$4	182,392,330	$0.02

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Common unit options	25,165	—	24,188	—
Phantom units	580,935	—	505,235	—
Series A Preferred Units	2,057,662	4,672,835	2,055,949	4,672,835

4. Acquisitions

2014

Eagle Rock Midstream Acquisition. On July 1, 2014, the Partnership acquired Eagle Rock's midstream business (the "Eagle Rock Midstream Acquisition") for $1.3 billion, including the assumption of $499 million of Eagle Rock's 8.375% Senior Notes due 2019. The remainder of the purchase price was funded by $400 million in common units sold to ETE Common Holdings, 8.2 million common units issued to Eagle Rock, and borrowings under the revolving credit facility. The Partnership will account for the Eagle Rock Midstream Acquisition using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized on the balance sheet at their fair values as of the acquisition date. The evaluation of the assigned fair values is ongoing as the transaction was recently completed and therefore the Partnership was not able to complete the preliminary allocation of the purchase price to the acquired assets and liabilities prior to the issuance of these financial statements. This acquisition is expected to complement the Partnership's core gathering and processing business and, when combined with the PVR Acquisition, is expected to further diversify the Partnership's basin exposure in the Texas Panhandle, east Texas and south Texas.

PVR Acquisition. On March 21, 2014, the Partnership acquired PVR for a total purchase price of $5.7 billion (based on the Partnership's closing price of $27.82 per unit on March 21, 2014), including $1.8 billion principal amount of assumed debt ("PVR Acquisition"). PVR unitholders received (on a per unit basis) 1.02 Partnership common units and a one-time cash payment of $36.1 million, which was funded through borrowings under the Partnership's revolving credit facility. The PVR Acquisition enhances the Partnership's geographic diversity with a strategic presence in the Marcellus and Utica shales in the Appalachian Basin and the Granite Wash in the Mid-Continent region. The Partnership accounted for the acquisition of PVR using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized on the balance sheet at their fair values as of the acquisition date. Revenues attributable to PVR's operations included in the statement of operations for the three and six months ended June 30, 2014 were $314 million and $351 million, respectively. Net income attributable to PVR's operations included in the statement of operations for the three and six months ended June 30, 2014 were $33 million and $35 million, respectively.

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Management is in the process of finalizing the evaluation of the assigned fair values to the assets acquired and liabilities assumed. The total purchase was allocated as follows:

Assets	At March 21, 2014
Current assets	$140
Gathering and transmission systems	1,396
Compression equipment	342
Gas plants and buildings	110
Natural resources	454
Other property, plant and equipment	229
Construction in process	172
Investment in unconsolidated subsidiaries	62
Intangible assets	2,717
Goodwill [1]	353
Other long-term assets	18
Total Assets Acquired	$5,993
Liabilities	
Current liabilities	$161
Long-term debt	1,788
Premium related to senior notes	99
Long-term liabilities	42
Total Liabilities Assumed	$2,090
Net Assets Acquired	$3,903

[1] Goodwill is reported in the Gathering and Processing segment.

The fair values of the assets acquired and liabilities assumed were determined using various valuation techniques, including the income and market approaches.

Assets. Cash and cash equivalents, accounts receivable, net, other current assets, and construction in process, were valued using a cost basis as this basis approximates fair value due to the current nature of these items. Real property, including gathering and transmission systems, compression equipment, gas plants and buildings, and other property, plant and equipment, were valued based on a combination of the income, market and cost approaches, depending on the type of asset. Coal and timber reserves were valued using the income approach for active coal and timber reserves. The investments in unconsolidated subsidiaries were valued using the income approach. Intangible assets, other than goodwill, are customer contract related intangibles, which have an average useful life of 30 years, and have been valued using the income approach. The goodwill is the excess of the consideration transferred over the net assets recognized and represents the future economic benefits arising from other assets acquired that could not be individually identified and separately recognized.

Liabilities. The Partnership assumed accounts payable, accrued liabilities, deferred income, and other long-term liabilities as part of the PVR Acquisition. The Partnership determined that the historical cost basis of these liabilities approximated fair value as they comprise normal operating liabilities. The Partnership assumed long-term debt as part of the acquisition, consisting of amounts outstanding under PVR's revolving credit facility and PVR's outstanding senior notes. The amount related to the revolving credit facility was valued at historical book value while the senior notes were valued using quoted market prices, which are considered Level 1 inputs.

Change in Control. The PVR Acquisition constituted a change of control for certain PVR employment agreements. Pursuant to the terms of those agreements, certain payments and benefits, including severance payments, were triggered by the PVR Acquisition. From the date of the PVR Acquisition, the Partnership has recorded $10 million of severance payments due to the change in control. Additionally, the Partnership has recorded $2 million in retention bonuses that are payable to various retained PVR employees upon the expiration of their retention period.

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Hoover Energy Acquisition. On February 3, 2014, the Partnership acquired certain subsidiaries of Hoover for a total purchase price of $293.2 million, consisting of (i) 4,040,471 common units issued to Hoover and (ii) $183.6 million in cash, and (iii) $2 million in asset retirement obligations assumed (the “Hoover Acquisition”). The Hoover Acquisition increases the Partnership’s fee-based revenue, expanding its existing footprint in the southern portion of the Delaware Basin in west Texas, and its services to producers into crude and water gathering. A portion of the consideration is being held in escrow as security for certain indemnification claims. The Partnership financed the cash portion of the purchase price through borrowings under its revolving credit facility. The Partnership accounted for the Hoover Acquisition using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized on the balance sheet at their fair values as of the acquisition date. Revenues attributable to Hoover’s operations included in the statement of operations for the three and six months ended June 30, 2014 were $10 million and $15 million, respectively. Net income attributable to Hoover’s operations included in the statement of operations for the three and six months ended June 30, 2014 were $2 million and $4 million, respectively.

Management completed the evaluation of the assigned fair values to the assets acquired and liabilities assumed. The total purchase price was allocated as follows:

Assets	At February 3, 2014
Accounts receivable, net	$5
Gathering and transmission systems	72
Compression equipment	15
Other property, plant, and equipment	22
Construction in process	6
Intangible assets	148
Goodwill [1]	30
Total Assets Acquired	$298
Liabilities	
Accounts payable and accrued liabilities	$5
Asset retirement obligation	2
Total Liabilities Assumed	$7
Net Assets Acquired	$291

[1] Goodwill is reported in the Gathering and Processing segment.

The fair values of the assets acquired and liabilities assumed were determined using various valuation techniques, including the income and market approaches.

Assets. Accounts receivable, net, other current assets, and construction in process were valued using a cost basis as this basis approximates fair value due to the current nature of these items. Real property, including gathering and transmission systems, compression equipment, and other property, plant and equipment, were valued based on a combination of the income, market and cost approaches, depending on the type of asset. Intangible assets, other than goodwill, are customer contract related intangibles, which have an average useful life of 30 years, and have been valued using the income approach. The goodwill is the excess of the consideration transferred over the net assets recognized and represents the future economic benefits arising from other assets acquired that could not be individually identified and separately recognized.

Liabilities. The Partnership assumed accounts payable, accrued liabilities, and an asset retirement obligation as part of the Hoover Acquisition. The Partnership determined that the historical cost basis of the accounts payable and the accrued liabilities approximated fair value as they comprise normal operating liabilities. The asset retirement obligation was valued based on estimates prepared by an independent environmental consulting firm.

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Pro Forma Results of Operations

The following unaudited pro forma consolidated results of operations for the three and six months ended June 30, 2014 and 2013 are presented as if the PVR and Hoover acquisitions had been completed on January 1, 2013. The pro forma information includes adjustments to reflect incremental expenses associated with the fair value adjustments recorded as a result of applying the acquisition method of accounting and incremental interest expense related to the financing of a portion of the purchase price. This pro forma information is not necessarily indicative of the results that would have occurred had the acquisitions occurred on January 1, 2013, nor is it indicative of future results of operations.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Revenues	$1,178	$923	$2,323	$1,731
Net loss attributable to the Partnership	(18)	(20)	(53)	(78)
Basic net loss per Limited Partner unit	$(0.05)	$(0.07)	$(0.16)	$(0.27)
Diluted net loss per Limited Partner unit	$(0.05)	$(0.07)	$(0.16)	$(0.27)

5. Investment in Unconsolidated Affiliates

As of June 30, 2014, 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, a 51% membership interest in Aqua - PVR, and a 50% interest in Coal Handling. The Partnership’s interest in the Aqua - PVR and Coal Handling joint ventures was acquired in the PVR Acquisition. In March 2014, the Partnership entered into a settlement agreement, whereby the Partnership’s 50% interest in Grey Ranch was assigned to SandRidge Midstream, Inc., resulting in a cash settlement of $4 million and a loss of $1 million recorded to income from unconsolidated affiliates. In June 2014, the Partnership agreed to guarantee the prompt payment by Regency Midcontinent Express LLC of its proportionate $175 million capital contributions to MEP. The Partnership’s obligation is not expected to exceed $176 million.

The carrying value of the Partnership’s investment in each of the unconsolidated affiliates as of June 30, 2014 and December 31, 2013 is as follows:

	June 30, 2014	December 31, 2013
HPC	$434	$442
MEP	709	548
Lone Star	1,135	1,070
Ranch JV	39	36
Aqua - PVR	50	—
Coal Handling	11	—
Grey Ranch	—	1
Total	$2,378	$2,097

The following tables summarize the Partnership’s investment activities in each of the unconsolidated affiliates for the three and six months ended June 30, 2014 and 2013:

	Three Months Ended June 30, 2014					
	HPC	MEP	Lone Star	Ranch JV	Aqua - PVR	Coal Handling
Contributions to unconsolidated affiliates	$—	$175	$44	$—	$—	$—
Distributions from unconsolidated affiliates	(11)	(19)	(32)	(1)	—	—
Share of earnings of unconsolidated affiliates’ net income (loss)	8	12	27	3	(1)	—
Amortization of excess fair value of investment	(2)	—	—	—	—	—

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

	Six Months Ended June 30, 2014					
	HPC	MEP	Lone Star	Ranch JV	Aqua - PVR	Coal Handling
Contributions to unconsolidated affiliates	$—	$175	$71	$—	$—	$—
Distributions from unconsolidated affiliates	(21)	(37)	(57)	(1)	—	—
Share of earnings of unconsolidated affiliates' net income (loss)	16	22	51	5	(1)	—
Amortization of excess fair value of investment	(3)	—	—	—	—	—

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

The following tables present selected income statement data for each of the unconsolidated affiliates, on a 100% basis, for the three and six months ended June 30, 2014 and 2013:

	Three Months Ended June 30, 2014					
	HPC	MEP	Lone Star	Ranch JV	Aqua - PVR	Coal Handling
Total revenues	$37	$66	$880	$11	$1	$3
Operating income (loss)	20	35	90	7	(3)	1
Net income (loss)	16	23	89	8	(2)	1

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

	Six Months Ended June 30, 2014					
	HPC	MEP	Lone Star	Ranch JV	Aqua - PVR	Coal Handling
Total revenues	$74	$132	$1,693	$20	$1	$3
Operating income (loss)	38	69	174	14	(3)	1
Net income (loss)	31	44	172	14	(2)	1

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

6. 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 overseeing the 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.

Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under its revolving credit facility. As of June 30, 2014, the Partnership had $850 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 June 30, 2014 would be $2 million, which would be reduced by $1 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.

The Partnership's derivative assets and liabilities, including credit risk adjustments, as of June 30, 2014 and December 31, 2013 are detailed below:

	Assets		Liabilities	
	June 30, 2014	December 31, 2013	June 30, 2014	December 31, 2013
Derivatives not designated as cash flow hedges				
Current amounts				
Commodity contracts	$2	$3	$11	$9
Long-term amounts				

Commodity contracts	—	1	—	—
Embedded derivatives in Series A Preferred Units	—	—	29	19
Total derivatives	$2	$4	$40	$28

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The Partnership's statements of operations for the three and six months ended June 30, 2014 and 2013 were impacted by derivative instruments activities as follows:

		Three Months Ended June 30,	
		2014	2013
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	$(5)	$14
Embedded derivatives in Series A Preferred Units	Other income & deductions, net	(9)	(8)
		$(14)	$6

		Six Months Ended June 30,	
		2014	2013
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	$(18)	$11
Embedded derivatives in Series A Preferred Units	Other income & deductions, net	(10)	(22)
		$(28)	$(11)

7. Long-term Debt

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

	June 30, 2014	December 31, 2013
Senior notes	$4,572	$2,800
Revolving loans	850	510
Unamortized premium and discounts	68	—
Long-term debt	$5,490	$3,310
Availability under revolving credit facility:		
Total credit facility limit	$1,500	$1,200
Revolving loans	(850)	(510)
Letters of credit	(28)	(14)
Total available	$622	$676

Long-term debt maturities as of June 30, 2014 for each of the next five years are as follows:

Years Ending December 31,	Amount
2014 (remainder)	$—
2015	—
2016	—
2017	—
2018	600
Thereafter	4,822
Total *	$5,422

* Excludes a $82 million unamortized premium on the PVR senior notes assumed by the Partnership and a $14 million unamortized discount on the 2022 Notes.

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Revolving Credit Facility

In February 2014, RGS entered into the First Amendment to the Sixth Amended and Restated Credit Agreement (as amended, the "Credit Agreement") to, among other things, expressly permit the pending PVR and Eagle Rock Midstream acquisitions, and to increase the commitment to $1.5 billion and increase the uncommitted incremental facility to $500 million. The amendment specifically allows the Partnership to assume the series of PVR senior notes that mature prior to the Credit Agreement.

The weighted average interest rate on the total amounts outstanding under the Partnership's revolving credit facility was 2.66% as of June 30, 2014.

Senior Notes

In February 2014, the Partnership and Finance Corp. issued $900 million of senior notes that mature on March 1, 2022 (the "2022 Notes"). The 2022 Notes bear interest at 5.875% with interest payable semi-annually in arrears on September 1 and March 1. At any time prior to December 1, 2021, the Partnership may redeem some or all of the notes at 100% of the principal amount thereof, plus a "make-whole" redemption price and accrued and unpaid interest, if any, to the redemption date. On or after December 1, 2021, the Partnership may redeem some or all of the notes at a redemption price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date. If the Partnership undergoes certain change of control transactions, the Partnership may be required to offer to purchase the notes from holders. The 2022 Notes are guaranteed by the Partnership's existing consolidated subsidiaries except Finance Corp and ELG. The 2022 Notes rank equally in right of payment with all of the Partnership's existing and future senior unsecured debt, including the Partnership's other outstanding Senior Notes, and contain the same covenants as the Partnership's other existing Senior Notes.

In March 2014, in connection with the PVR Acquisition, the Partnership assumed $1.2 billion in aggregate principal amount of PVR's outstanding senior notes, consisting of $300 million of 8.25% senior notes that mature on April 15, 2018 (the "2018 PVR Notes"), $400 million of 6.5% senior notes that mature on May 15, 2021 (the "2021 PVR Notes"), and $473 million of 8.375% senior notes that mature on June 1, 2020 (the "2020 PVR Notes"). In April 2014, the Partnership redeemed all of the 2018 PVR Notes for $313 million at a price of 104.125% plus accrued and unpaid interest paid to the redemption date. Interest on the 2021 PVR Notes and the 2020 PVR Notes accrue semi-annually on May 15 and November 15 and June 1 and December 1, respectively.

On March 24, 2014, in accordance with our obligations under the indentures governing the 2020 PVR Notes and the 2021 PVR Notes, we commenced change of control offers pursuant to which holders of such notes were entitled to require us to repurchase all or a portion of their notes at a purchase price of 101% of the principal amount thereof, plus accrued and unpaid interest to the repurchase date. The change of control offers for the 2020 PVR Notes and the 2021 PVR Notes expired on April 22, 2014 and, on April 23, 2014, we accepted for purchase less than $1 million in aggregate principal amount of 2021 PVR Notes.

In July 2014, the Partnership exchanged $499 million of 8.375% Senior Notes due 2019 (the "Eagle Rock Notes") of Eagle Rock and Eagle Rock Energy Finance Corp. for 8.375% Senior Notes due 2019 to be issued by the Partnership and Finance Corp. (the "New Partnership Notes"). The New Partnership Notes will have substantially the same economic terms as the outstanding Eagle Rock Notes, including interest rate, interest payment dates, optional redemption terms and maturity. The New Partnership Notes will rank equally with the Partnership's existing Senior Notes.

In July 2014, the Partnership and Finance Corp. issued $700 million of senior notes that mature on October 1, 2022 (the "October 2022 Notes"). The October 2022 Notes bear interest at 5% with interest payable semi-annual in arrears on October 1 and April 1, beginning April 1, 2015. At any time prior to July 1, 2022, the Partnership may redeem some or all of the notes at 100% of the principal amount thereof, plus a "make-whole" redemption price and accrued and unpaid interest, if any, to the redemption date. On or after, July 1, 2022, the Partnership may redeem some or all of the notes at a redemption price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date. If the Partnership undergoes certain change of control transactions, it may be required to offer to purchase the notes from holders. The October 2022 Notes are guaranteed by substantially all of the Partnership's consolidated subsidiaries. In accordance with the terms of the October 2022 Notes, the acquired Eagle Rock entities will become guarantors of the October 2022 Notes within 20 business days of their guarantee of the Partnership's obligations under the revolving credit facility, which is required to occur within 30 days of the closing of the Eagle Rock Midstream Acquisition. The October 2022 Notes will rank equally in right of payment with all of its existing and future senior unsecured debt, including its other outstanding Senior Notes, and contain substantially the same covenants as its other existing Senior Notes.

In July 2014, the Partnership redeemed $83 million of the $473 million outstanding 2020 PVR Notes for $91 million, including $8 million of accrued interest and redemption premium.
At June 30, 2014, the Partnership was in compliance with all material covenants under the Credit Agreement and indentures governing the Senior Notes.

The Senior Notes issued by the Partnership and Finance Corp. are fully and unconditionally guaranteed, on a joint and several basis, by the Partnership's existing, 100% owned, consolidated subsidiaries, except for ELG and Aqua - PVR.

8. 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.

PVR Shareholder Litigation. Five putative class action lawsuits challenging the PVR Acquisition are currently pending. All of the cases name PVR, PVR GP and the current directors of PVR GP, as well as the Partnership and the General Partner (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, that PVR GP, PVR and the Regency Defendants aided and abetted the directors of PVR GP in the alleged breach of these fiduciary duties, and, as to the actions in federal court, that some or all of PVR, PVR GP, and the directors of PVR GP violated Section 14(a) of the Exchange Act and Rule 14a-9 promulgated thereunder and Section 20(a) of the Exchange Act. The lawsuits purport to seek, in general, (i) injunctive relief, (ii) disclosure of certain additional information concerning the transaction, (iii) in the event the merger is consummated, rescission or an award of rescissory damages, (iv) an award of plaintiffs' costs and (v) the accounting for damages allegedly causes by the defendants to these actions, and, (iv) such further relief as the court deems just and proper. The styles of the pending cases are as follows: David Naiditch v. PVR Partners, L.P., et al. (Case No. 9015-VCL) in the Court of Chancery of the State of Delaware); Charles Monatt v. PVR Partners, LP, et al. (Case No. 2013-10606) and Saul Srour v. PVR Partners, L.P., et al. (Case No. 2013-011015), each pending in the Court of Common Pleas for Delaware County, Pennsylvania; Stephen Bushansky v. PVR Partners, L.P., et al. (C.A. No. 2:13-cv-06829-HB); and Mark Hinnau v. PVR Partners, L.P., et al. (C.A. No. 2:13-cv-07496-HB), pending in the United States District Court for the Eastern District of Pennsylvania.

On January 28, 2014, the defendants entered into a Memorandum of Understanding ("MOU") with Monatt, Srour, Bushansky, Naiditch and Hinnau pursuant to which defendants and the referenced plaintiffs agreed in principle to a settlement of their lawsuits ("Settled Lawsuits"), which will be memorialized in a separate settlement agreement, subject to customary conditions, including consummation of the PVR Acquisition, which occurred on March 21, 2014, completion of certain confirmatory discovery, class certification and final approval by the Court of Common Pleas for Delaware County, Pennsylvania. If the Court approves the settlement, the Settled Lawsuits will be dismissed with prejudice and all defendants will be released from any and all claims relating to the Settled Lawsuits.

The settlement will not affect any provisions of the merger agreement or the form or amount of consideration received by PVR unitholders in the PVR Acquisition. The defendants have denied and continue to deny any wrongdoing or liability with respect to the plaintiffs' claims in the aforementioned litigation and have entered into the settlement to eliminate the uncertainty, burden, risk, expense, and distraction of further litigation.

Utility Line Services, Inc. vs. PVR Marcellus Gas Gathering LLC. On May 22, 2012, Plaintiff and Counterclaim Defendant, Utility Line Services, Inc. ("ULS") filed suit against PVR Marcellus Gas Gathering, LLC now known as Regency Marcellus Gas Gathering LLC ("Regency Marcellus") relating to a dispute involving payment under a construction contract (the "Construction Contract") entered into in October 2010 for Regency Marcellus' multi-phase pipeline construction project in Lycoming County, PA (the "Project"). Under the terms of the Construction Contract, Regency Marcellus believed ULS was obligated to design, permit and build Phases I and II of Regency Marcellus' 30-inch pipeline and to design additional phases of the project. Due to ULS' deficiencies and delays throughout the project, as well as extensive overbilling for its services, Regency Marcellus allowed the Construction Contract to terminate in accordance with its terms in December 2011 and refused to pay ULS' outstanding invoices for the Project. ULS then filed suit alleging: Regency Marcellus' refusal to pay certain invoices totaling approximately $17 million; penalties pursuant to the Pennsylvania Contractor and Subcontractor Payment Act, 73 P.S. § 501, et seq. ("CASPA"), Regency Marcellus' alleged wrongful withholding of payments owed to ULS; and breach of contract in connection with Regency Marcellus' alleged wrongful termination of ULS in December 2011. ULS alleged damages, inclusive of

CASPA penalties, are in excess of $30 million. Regency Marcellus alleged counterclaims against ULS for breach of the parties' contract for engineering and construction services; restitution for Regency Marcellus' overpayments to ULS because of ULS' improper billing practices; attorneys' fees resulting from ULS' meritless claim under CASPA; and professional malpractice against ULS for negligent performance of various engineering services on the Project. Regency Marcellus' alleged damages exceed $21 million.

Trial commenced on March 24, 2014 and on April 17, 2014, the jury found in favor of ULS and assessed damages against Regency Marcellus of approximately $24 million plus interest and penalties. In June 2014, ULS and Regency Marcellus reached a settlement

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in this matter, the terms of which are confidential. The settlement will not have a material adverse effect on the Partnership's business or financial position.

Eagle Rock Shareholder Litigation. Three putative class action lawsuits challenging the Eagle Rock Midstream Acquisition are currently pending in federal district court in Houston, Texas. All cases name Eagle Rock and its current directors, as well as the Partnership and a subsidiary, as defendants. One of the lawsuits also names additional Eagle Rock entities as defendants. Each of the lawsuits has been brought by a purported unitholder of Eagle Rock (collectively, the "Plaintiffs"), both individually and on behalf of a putative class consisting of public unitholders of Eagle Rock. The Plaintiffs in each case seek to rescind the transaction, claiming, among other things, that it yields inadequate consideration, was tainted by conflict and constitutes breaches of common law fiduciary duties or contractually imposed duties to the shareholders. Plaintiffs also seek monetary damages and attorneys' fees. The Partnership and its subsidiary are named as "aiders and abettors" of the allegedly wrongful actions of Eagle Rock and its board.

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.

The table below reflects the environmental liabilities recorded at June 30, 2014 and December 31, 2013. 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.

	June 30, 2014	December 31, 2013
Current	$2	$2
Noncurrent	8	6
Total environmental liabilities	$10	$8

The Partnership recorded less than $1 million in expenditures related to environmental remediation for the six months ended June 30, 2014.

Endangered Species Act. In March 2014, the U.S. Fish & Wildlife Service listed the lesser prairie chicken as a "threatened" species under the federal Endangered Species Act. This species is predominantly located in the Partnership's Permian and Midcontinent regions; therefore, the Partnership may encounter additional costs and delays in infrastructure development. The Partnership is participating, along with other companies in our industry, in a conservation plan for this species, which will allow the Partnership to participate in managing the related conservation efforts.

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. The Partnership 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 compliance orders were delayed until October 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.

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Mine Health and Safety Laws. There are numerous mine health and safety laws and regulations applicable to the coal mining industry. However, since the Partnership does not operate any mines and does not employ any coal miners, it is not subject to such laws and regulations. Accordingly, the Partnership has not accrued any related liabilities.

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.

9. Related Party Transactions

As of June 30, 2014 and December 31, 2013, details of the Partnership's related party receivables and related party payables were as follows:

	June 30, 2014	December 31, 2013
Related party receivables		
ETE and its subsidiaries	$17	$25
HPC	2	1
Ranch JV	—	2
Total related party receivables	$19	$28
Related party payables		
ETE and its subsidiaries	$39	$68
HPC	1	1
MEP	175	—
Total related party payables	$215	$69

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 has a five year term ending 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, this agreement was amended to provide for a waiver of the $10 million annual fee effective as of May 1, 2013 through and including April 30, 2015 and to clarify 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 $1 million and $2 million for the three months ended June 30, 2014 and 2013, respectively, and $3 million and $7 million for the six months ended June 30, 2014 and 2013, respectively.

In conjunction with distributions by the Partnership to the limited and general partner interests, ETE received cash distributions of $20 million and $15 million for the three months ended June 30, 2014 and 2013, respectively, and $37 million and $31 million for the six months ended June 30, 2014 and 2013, respectively.

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 $22 million and $14 million during the three months ended June 30, 2014 and 2013, respectively, and $31 million and $25 million for the six months ended June 30, 2014 and 2013, respectively.

Transactions with Lone Star. Subsidiaries of the Partnership have entered into various agreements to sell NGLs to Lone Star. For the six months ended June 30, 2014, the Partnership had recorded $112 million in NGL sales under these contracts of which the unsettled portion are included in the related party receivable from ETE and its subsidiaries.

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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.

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 for the three months ended June 30, 2014 and 2013, and $8 million and $10 million for the six months ended June 30, 2014 and 2013, respectively, which are recorded in gathering, transportation and other fees.

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

10. Segment Information

The Partnership has six reportable segments: Gathering and Processing, Natural Gas Transportation, NGL Services, Contract Services, Natural Resources 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, the gathering of oil (crude and/or condensate, a lighter oil) received from producers, and the gathering and disposing of salt water. This segment also includes ELG, which operates natural gas gathering, oil pipeline, and oil stabilization facilities in south Texas, the Partnership's 33.33% membership interest in Ranch JV, which processes natural gas delivered from NGL-rich shale formations in west Texas, and the Partnership's 51% interest in Aqua - PVR, which transports and supplies fresh water to natural gas producers in the Marcellus shale in Pennsylvania. The Partnership completed the SUGS Acquisition on April 30, 2013 which was a reorganization of entities under common control. Therefore, the Gathering and Processing segment amounts have been retrospectively adjusted to reflect the SUGS Acquisition for the three and six months ended June 30, 2013.
- 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.
- Natural Resources. The Partnership is involved in the management of coal and natural resources properties and the related collection of royalties. The Partnership also earns revenues from other land management activities, such as selling standing timber, leasing coal-related infrastructure facilities, and collecting oil and gas royalties. This segment also includes the Partnership's 50% interest in Coal Handling, which owns and operates end-user coal handling facilities.
- 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,

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segment margin is defined as revenues less direct costs. The Natural Resources segment margin is generally equal to total revenues as there is typically minimal cost of sales associated with the management and leasing of properties. 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, Aqua - PVR, and Coal Handling) 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 June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
External Revenues				
Gathering and Processing	$1,074	$583	$1,867	$1,069
Natural Gas Transportation	—	—	—	—
NGL Services	—	—	—	—
Contract Services	78	52	141	101
Natural Resources	20	—	22	—
Corporate	6	4	11	9
Eliminations	—	—	—	—
Total	$1,178	$639	$2,041	$1,179
Intersegment Revenues				
Gathering and Processing	$—	$—	$—	$—
Natural Gas Transportation	—	—	—	—
NGL Services	—	—	—	—
Contract Services	4	4	8	7
Natural Resources	—	—	—	—
Corporate	—	—	—	—
Eliminations	(4)	(4)	(8)	(7)
Total	$—	$—	$—	$—
Segment Margin				
Gathering and Processing	$269	$145	$435	$248
Natural Gas Transportation	—	—	—	—
NGL Services	—	—	—	—
Contract Services	63	49	119	97
Natural Resources	20	—	22	—
Corporate	2	4	7	9
Eliminations	(4)	(4)	(8)	(7)
Total	$350	$194	$575	$347
Operation and Maintenance				
Gathering and Processing	$71	$60	$132	$114
Natural Gas Transportation	—	—	—	—
NGL Services	—	—	—	—
Contract Services	21	17	41	35
Natural Resources	5	—	5	—
Corporate	—	—	1	—
Eliminations	(4)	(4)	(8)	(7)
Total	$93	$73	$171	$142

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Total segment margin	$350	$194	$575	$347
Operation and maintenance	(93)	(73)	(171)	(142)
General and administrative	(54)	(18)	(87)	(51)
Gain (loss) on asset sales, net	—	(1)	2	(2)
Depreciation, depletion and amortization	(168)	(68)	(262)	(133)
Income from unconsolidated affiliates	47	31	90	66
Interest expense, net	(78)	(41)	(134)	(78)
Loss on debt refinancing, net	—	(7)	—	(7)
Other income and deductions, net	(7)	(7)	(5)	(21)
(Loss) income before income taxes	$(3)	$10	$8	$(21)

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

Total Assets	June 30, 2014	December 31, 2013
Gathering and Processing	$10,285	$4,748
Natural Gas Transportation	1,144	991
NGL Services	1,135	1,070
Contract Services	2,007	1,897
Natural Resources	514	—
Corporate	374	76
Total	$15,459	$8,782

Investment in Unconsolidated Affiliates	June 30, 2014	December 31, 2013
Gathering and Processing	$89	$36
Natural Gas Transportation	1,143	991
NGL Services	1,135	1,070
Natural Resources	11	—
Total	$2,378	$2,097

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 $3 million and $1 million was recorded in general and administrative expense for the three months ended June 30, 2014 and 2013, respectively, and $5 million and $3 million for the six months ended June 30, 2014 and 2013, respectively.

Phantom Units. Phantom units granted during the period 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 the unvested phantom units are paid concurrent with the Partnership’s distribution for common units.

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The following table presents phantom units activity for the six months ended June 30, 2014:

Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at beginning of period	982,242	$23.16
Service condition grants	718,791	25.99
Vested service condition	(4,008)	26.53
Forfeited service condition	(72,185)	24.77
Outstanding at end of period	1,624,840	$24.33

The Partnership expects to recognize $30 million of compensation expense related to non-vested phantom units over a weighted-average period of 3.7 years.

12. Fair Value Measures

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

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

	Fair Value Measurements at June 30, 2014			Fair Value Measurements at December 31, 2013		
	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	$1	$1	$—	$2	$2	$—
NGLs	1	1	—	2	2	—
Total Assets	$2	$2	$—	$4	$4	$—
Liabilities						
Commodity Derivatives:						
Natural Gas	$5	$5	$—	$4	$4	$—
NGLs	2	2	—	4	4	—
Condensate	4	4	—	1	1	—
Embedded derivatives in Series A Preferred Units	29	—	29	19	—	19
Total Liabilities	$40	$11	$29	$28	$9	$19

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

Unobservable Input	June 30, 2014
Credit Spread	3.91 %
Volatility	21.40 %

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.

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The following table presents the changes in Level 3 derivatives measured on a recurring basis for the six months ended June 30, 2014. There were no transfers between the fair value hierarchy levels for the six months ended June 30, 2014.

	Embedded Derivatives in Series A Preferred Units
Net liability balance at December 31, 2013	$19
Change in fair value	10
Net liability balance at June 30, 2014	$29

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. Long-term debt, other than the Senior Notes, is comprised of borrowings under which interest accrues under a floating interest rate structure. Accordingly, the carrying value approximates fair value. The aggregate fair value and carrying amount of the Senior Notes at June 30, 2014 were $4.9 billion and $4.57 billion, respectively. As of December 31, 2013, the aggregate fair value and carrying amount of the Senior Notes were $2.83 billion and $2.80 billion, respectively. The fair value of the Senior Notes is a Level 1 valuation based on third party market value quotations.

13. Consolidating Guarantor Financial Information

ELG and Aqua - PVR do not fully and unconditionally guarantee, on a joint and several basis, the Senior Notes issued and outstanding as of June 30, 2014, by the Partnership and Finance Corp.. Included in the Parent financial statements are the Partnership's intercompany investments in all consolidated subsidiaries and the Partnership's investments in unconsolidated subsidiaries. ELG and Aqua - PVR are included in the non-guarantor subsidiaries.

The consolidating financial information for the Parent, Guarantor Subsidiaries, and Non Guarantor Subsidiaries are as follows:

	June 30, 2014				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
ASSETS					
Cash	$—	$15	$ 43	$(8)	$50
Intercompany accounts receivable	—	—	—	—	—
All other current assets	—	538	5	(1)	542
Property, plant, and equipment, net	—	7,236	269	(89)	7,416
Investment in subsidiaries	18,368	—	—	(18,368)	—
Investment in unconsolidated subsidiaries	—	2,221	—	157	2,378
All other assets	—	5,073	—	—	5,073
TOTAL ASSETS	$18,368	$15,083	$ 317	$(18,309)	$15,459
LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST					
Intercompany accounts payable	$—	$—	$ —	$—	$—
All other current liabilities	—	722	8	—	730
Long-term liabilities	4,673	937	3	(3)	5,610
Noncontrolling interest	—	—	—	107	107
Total partners' capital	13,695	13,424	306	(18,413)	9,012
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$18,368	$15,083	$ 317	$(18,309)	$15,459

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	December 31, 2013				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
ASSETS					
Cash	$—	$—	$ 19	$—	$19
Intercompany accounts receivable	—	615	—	(615)	—
All other current assets	—	366	15	—	381
Property, plant, and equipment, net	—	4,244	174	—	4,418
Investment in subsidiaries	10,446	—	—	(10,446)	—
Investment in unconsolidated subsidiaries	—	1,995	—	102	2,097
All other assets	—	1,867	—	—	1,867
TOTAL ASSETS	$10,446	$9,087	$ 208	$(10,959)	$8,782
LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST					
Intercompany accounts payable	$—	$615	$ —	$(615)	$—
All other current liabilities	—	466	9	—	475
Long-term liabilities	2,832	559	—	—	3,391
Noncontrolling interest	—	—	—	102	102
Total partners' capital	7,614	7,447	199	(10,446)	4,814
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$10,446	$9,087	$ 208	$(10,959)	$8,782

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	Three Months Ended June 30, 2014				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$—	$1,162	$ 16	$—	$1,178
Operating costs, expenses, and other	—	1,137	9	(3)	1,143
Operating income	—	25	7	3	35
Income from unconsolidated affiliates	—	48	—	(1)	47
Interest expense, net	(71)	(7)	—	—	(78)
Gain (loss) on debt refinancing, net	1	(1)	—	—	—
Equity in consolidated subsidiaries	73	—	—	(73)	—
Other income and deductions, net	(8)	1	—	—	(7)
(Loss) income before income taxes	(5)	66	7	(71)	(3)
Income tax expense	1	—	—	—	1
Net (loss) income	(6)	66	7	(71)	(4)
Net income attributable to noncontrolling interest	—	—	—	(4)	(4)
Net (loss) income attributable to Regency Energy Partners LP	$(6)	$66	$ 7	$(75)	$(8)
Total other comprehensive income (loss)	$—	$—	$ —	$—	$—
Comprehensive (loss) income	(6)	66	7	(71)	(4)
Comprehensive income attributable to noncontrolling interest	—	—	—	4	4
Comprehensive (loss) income attributable to Regency Energy Partners LP	$(6)	$66	$ 7	$(75)	$(8)

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	Three Months Ended June 30, 2013				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$—	$635	$ 4	$—	$639
Operating costs, expenses, and other	—	602	3	—	605
Operating income	—	33	1	—	34
Income from unconsolidated affiliates	—	31	—	—	31
Interest expense, net	(36)	(5)	—	—	(41)
Loss on debt refinancing, net	(7)	—	—	—	(7)
Equity in consolidated subsidiaries	62	—	—	(62)	—
Other income and deductions, net	(8)	1	—	—	(7)
Income before income taxes	11	60	1	(62)	10
Income tax benefit	—	(1)	—	—	(1)
Net income	11	61	1	(62)	11
Net income attributable to noncontrolling interest	—	—	—	(1)	(1)
Net income attributable to Regency Energy Partners LP	$11	$61	$ 1	$(63)	$10
Total other comprehensive income (loss)	$—	$—	$ —	$—	$—
Comprehensive income	11	61	1	(62)	11
Comprehensive income attributable to noncontrolling interest	—	—	—	1	1
Comprehensive income attributable to Regency Energy Partners LP	$11	$61	$ 1	$(63)	$10

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	Six Months Ended June 30, 2014				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$—	$2,011	$ 31	$(1)	$2,041
Operating costs, expenses, and other	—	1,972	15	(3)	1,984
Operating income	—	39	16	2	57
Income from unconsolidated affiliates	—	91	—	(1)	90
Interest expense, net	(121)	(13)	—	—	(134)
Gain (loss) on debt refinancing, net	1	(1)	—	—	—
Equity in consolidated subsidiaries	137	—	—	(137)	—
Other income and deductions, net	(9)	4	—	—	(5)
Income before income taxes	8	120	16	(136)	8
Income tax expense (benefit)	1	(2)	1	—	—
Net income	7	122	15	(136)	8
Net income attributable to noncontrolling interest	—	—	—	(7)	(7)
Net income attributable to Regency Energy Partners LP	$7	$122	$ 15	$(143)	$1
Total other comprehensive income (loss)	$—	$—	$ —	$—	$—
Comprehensive income	7	122	15	(136)	8
Comprehensive income attributable to noncontrolling interest	—	—	—	7	7
Comprehensive income attributable to Regency Energy Partners LP	$7	$122	$ 15	$(143)	$1

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	Six Months Ended June 30, 2013				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$—	$1,171	$ 8	$—	$1,179
Operating costs, expenses, and other	3	1,152	5	—	1,160
Operating (loss) income	(3)	19	3	—	19
Income from unconsolidated affiliates	—	66	—	—	66
Interest expense, net	(69)	(9)	—	—	(78)
Loss on debt refinancing, net	(7)	—	—	—	(7)
Equity in consolidated subsidiaries	83	—	—	(83)	—
Other income and deductions, net	(22)	1	—	—	(21)
(Loss) income before income taxes	(18)	77	3	(83)	(21)
Income tax benefit	—	(3)	—	—	(3)
Net (loss) income	(18)	80	3	(83)	(18)
Net income attributable to noncontrolling interest	—	—	—	(1)	(1)
Net (loss) income attributable to Regency Energy Partners LP	$(18)	$80	$ 3	$(84)	$(19)
Total other comprehensive income (loss)	$—	$—	$ —	$—	$—
Comprehensive (loss) income	(18)	80	3	(83)	(18)
Comprehensive income attributable to noncontrolling interest	—	—	—	1	1
Comprehensive (loss) attributable to Regency Energy Partners LP	$(18)	$80	$ 3	$(84)	$(19)

	Six Months Ended June 30, 2014				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows from operating activities	$—	$243	$ 35	$(1)	$277
Cash flows from investing activities	—	(657)	(5)	(8)	(670)
Cash flows from financing activities	—	429	(6)	1	424
Change in cash	—	15	24	(8)	31
Cash at beginning of period	—	—	19	—	19
Cash at end of period	$—	$15	$ 43	$(8)	$50

	Six Months Ended June 30, 2013				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows from operating activities	$—	$185	$ 10	$—	$195
Cash flows from investing activities	—	(882)	(76)	—	(958)
Cash flows from financing activities	—	697	30	—	727
Change in cash	—	—	(36)	—	(36)
Cash at beginning of period	—	—	53	—	53
Cash at end of period	$—	$—	$ 17	$—	$17

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, 2013.
OVERVIEW. We are a growth-oriented publicly-traded Delaware limited partnership engaged in the gathering and processing, compression, treating and transportation of natural gas; the transportation, fractionation and storage of NGLs; the gathering, transportation and terminaling of oil (crude, and/or condensate, a lighter oil) received from producers; and the management of coal and natural resource properties in the United States. 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. On February 3, 2014, we completed our acquisition of subsidiaries of Hoover that are engaged in crude oil gathering, transportation and terminaling, condensate handling, natural gas gathering, treating, and processing and water gathering and disposal services in the Southern Delaware Basin in west Texas. On March 21, 2014, we completed our previously announced acquisition of PVR. The PVR Acquisition enhances our geographic diversity with a strategic presence in the Marcellus and Utica shales in the Appalachian Basin and the Granite Wash in the Mid-Continent region. On July 1, 2014, we completed our previously announced acquisition of Eagle Rock's midstream business. The Eagle Rock Midstream Acquisition complements our gathering and processing business and is expected to further diversify our basin exposure in the Texas Panhandle, east Texas and south Texas.
RECENT DEVELOPMENTS.
Hoover Energy Acquisition. On February 3, 2014, we acquired certain subsidiaries of Hoover for a total purchase price of $293.2 million, consisting of (i) 4,040,471 common units issued to Hoover, (ii) $183.6 million in cash, and (iii) $2 million in asset retirement obligations assumed. The Hoover Acquisition increases our fee-based revenue and expands our existing footprint in the southern portion of the Delaware Basin in west Texas and our services to producers into crude and water gathering. A portion of the consideration is being held in escrow as security for certain indemnification claims. We financed the cash portion of the purchase price through borrowings under our revolving credit facility.

PVR Acquisition. On March 21, 2014, we acquired PVR for a total purchase price of $5.7 billion (based on our closing price of $27.82 per unit on March 21, 2014), including $1.8 billion of assumed debt. PVR unitholders received (on a per unit basis) 1.02 common units and a one-time cash payment of $36.1 million, which was funded through borrowings under our revolving credit facility. The PVR Acquisition enhances our geographic diversity with a strategic presence in the Marcellus and Utica shales in the Appalachian Basin and the Granite Wash in the Mid-Continent region.

Dubberly Expansion. In May 2014, we announced that we will construct a new processing plant and NGL pipeline at our Dubberly facility in North Louisiana and will include the addition of a new 200 MMcf/d cryogenic processing plant at the existing Dubberly facility, which will accept gas directly from our recently completed Dubberly gathering trunkline. The residue outlet for this facility will be RIGS. In addition, we will construct a new, 160-mile, 8 and 10 inch NGL pipeline from Dubberly for delivery to fractionation facilities in Louisiana and Texas. The pipeline will have an initial capacity of 25,000 Bbls/d, and will be expandable via additional pump stations. Combined project costs are expected to be $260 million and both the new processing facility and the NGL pipeline are backed by fee-based contracts. The projects are expected to be completed in mid-2015.

Eagle Rock Midstream Acquisition. On July 1, 2014, we acquired Eagle Rock's midstream business for $1.3 billion, including the issuance of 8.2 million Regency common units to Eagle Rock and the assumption of $499 million of

Eagle Rock’s 8.375% Senior Notes due 2019. The remainder of the purchase price was funded by $400 million in common units issued to ETE and borrowings under the revolving credit facility. This acquisition is expected to complement our core gathering and processing business, and when combined with the PVR Acquisition, is expected to further diversify our basin exposure in the Texas Panhandle, east Texas and south Texas.

Utica Ohio River Project. In August 2014, we entered into a joint venture agreement with American Energy - Midstream, LLC (“AEM”) for the construction and operation of a 52-mile, 36-inch gathering trunkline that will be capable of delivering up to 2.1 bcf/d to Rockies Express Pipeline (“REX”) and Texas Eastern Transmission. The project will also consist of the construction of 25,000 horsepower of compression at the REX interconnect (“Utica Ohio River Project”). The full project is expected to be completed in the third quarter of 2015. Total project costs are expected to be in excess of $500 million, 75% contributed from us and 25% contributed from AEM. Additionally, we and American Energy - Utica, LLC (“AEU”) entered into a gathering agreement

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for gas produced from the Utica Shale in eastern Ohio by AEU. All previously signed agreements will be contributed to the joint venture, including volume commitments and large acreage dedications.

OUR OPERATIONS. We divide our operations into the following six business segments:

- 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 pipeline-quality natural gas and NGLs to various markets and pipeline systems, the gathering, transportation and terminaling of oil (crude and/or condensate, a lighter oil) received from producers, and the gathering and disposing of salt water. This segment also includes ELG, which operates natural gas gathering, oil pipeline, and oil stabilization facilities in south Texas, our 33.33% membership interest in Ranch JV, which processes natural gas delivered from NGL-rich shale formations in west Texas, and our 51% interest in Aqua - PVR, which transports and supplies fresh water to natural gas producers in the Marcellus shale in Pennsylvania. We completed the SUGS Acquisition on April 30, 2013 which was a reorganization of entities under common control. Therefore, the Gathering and Processing segment amounts have been retrospectively adjusted to reflect the SUGS Acquisition for the three months ended March 31, 2013.
- 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, New Mexico, 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 and dehydration.
- Natural Resources. We are involved in the management and leasing of coal properties and the related collection of royalties. We also earn revenues from other land management activities, such as selling standing timber, leasing coal-related infrastructure facilities, and collecting oil and gas royalties. This segment also includes our 50% interest in Coal Handling, which owns and operates end-user coal handling facilities.
- Corporate. The Corporate segment comprises our corporate assets.

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

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

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

We do not record segment margin for our investments in unconsolidated affiliates (HPC, MEP, Lone Star, Ranch JV, Aqua - PVR, and Coal Handling) because we record our ownership percentage of their net income as income from unconsolidated affiliates in accordance with the equity method of accounting.

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

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Our Natural Resources segment margin is generally equal to total revenues as there is typically minimal cost of sales associated with the management and leasing of these properties.

We calculate total segment margin as the total of segment margin of our six 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 our Contract Services 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.

Coal Royalty Tonnage. Coal royalty tonnage is the primary driver of the value of our coal royalty revenues in our Natural Resources segment. We earn most of our coal royalty revenues under long-term leases that generally require our lessees to make royalty payments to us based on the higher of a percentage of the gross sales price or a fixed price per ton of coal they sell. The balance of our coal royalties revenues is earned under long-term leases that require the lessees to make royalty payments to us based on fixed royalty rates that escalate annually.

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, depletion 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;
- our interest in ELG adjusted EBITDA less adjusted EBITDA attributable to ELG; and
- our interest in adjusted EBITDA from unconsolidated affiliates less income from unconsolidated affiliates.

These measures are used as supplemental measures by our management and by external users of our financial statements such as investors, banks, research analysts and others, to assess:

- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our unitholders and General Partner;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

Neither EBITDA nor adjusted EBITDA should be considered an alternative to, or more meaningful than net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. EBITDA and adjusted EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate EBITDA or adjusted EBITDA in the same manner. Adjusted EBITDA is the starting point in determining distributable cash flow, which is an important non-GAAP financial measure for a publicly traded Partnership.

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EBITDA and adjusted EBITDA do not include interest expense, income tax expense or depreciation, depletion and amortization expense. Because we have borrowed money to finance our operations, interest expense is a necessary element of our costs and our ability to generate cash available for distribution. Because we use capital assets, depreciation, depletion and amortization are also necessary elements of our costs. Therefore, any measures that exclude these elements have material limitations. To compensate for these limitations, we believe that it is important to consider both net earnings determined under GAAP, as well as EBITDA and adjusted EBITDA, to evaluate our performance.

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:

	Six Months Ended June 30,	
Reconciliation of "Adjusted EBITDA" to net cash flows provided by operating activities and net income (loss)	2014	2013
Net cash flows provided by operating activities	$277	$195
Add (deduct):		
Depreciation, depletion and amortization, including debt issuance cost amortization and bond premium write-off and amortization	(264)	(137)
Income from unconsolidated affiliates	90	66
Derivative valuation change	(13)	(17)
Gain (loss) on asset sales, net	2	(2)
Unit-based compensation expenses	(5)	(3)
Trade accounts receivable and related party receivables	17	41
Other current assets and other current liabilities	(26)	51
Trade accounts payable and related party payables	36	(10)
Distributions of earnings received from unconsolidated affiliates	(96)	(71)
Cash flow changes in other assets and liabilities	(10)	(131)
Net income (loss)	8	(18)
Add (deduct):		
Interest expense, net	134	78
Depreciation, depletion and amortization expense	262	133
Income tax benefit	—	(3)
EBITDA	404	190
Add (deduct):		
Partnership's interest in unconsolidated affiliates' adjusted EBITDA	154	123
Income from unconsolidated affiliates	(90)	(66)
Non-cash loss from commodity and embedded derivatives	13	14
Other expense, net	31	13
Adjusted EBITDA	$512	$274

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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 six months ended June 30, 2014 and 2013 (The adjusted EBITDA for our investments in Aqua - PVR and Coal Handling from March 21, 2014 (the acquisition date) to March 31, 2014 was not material):

	Six Months Ended June 30, 2014						
	HPC	MEP	Lone Star	Ranch JV	Aqua - PVR	Coal Handling	Total
Net income (loss)	$31	$44	$172	$14	$(2)	$1	
Add:							
Depreciation, depletion and amortization	19	35	51	3	3	—	
Income tax expense	—	—	1	—	—	—	
Interest expense, net	6	25	—	—	—	—	
Adjusted EBITDA	56	104	224	17	1	1	
Ownership interest	49.99%	50%	30%	33.33%	51%	50%	
Partnership's interest in adjusted EBITDA	$28	$52	$67	$6	$1	$—	$154

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

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The following table presents a reconciliation of total segment margin and adjusted total segment margin to net (loss) income for the three and six months ended June 30, 2014 and 2013 for the Partnership:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net (loss) income	$(4)	$11	$8	$(18)
Add (deduct):				
Operation and maintenance	93	73	171	142
General and administrative	54	18	87	51
Loss (Gain) on asset sales, net	—	1	(2)	2
Depreciation, depletion and amortization	168	68	262	133
Income from unconsolidated affiliates	(47)	(31)	(90)	(66)
Interest expense, net	78	41	134	78
Loss on debt refinancing, net	—	7	—	7
Other income and deductions, net	7	7	5	21
Income tax expense (benefit)	1	(1)	—	(3)
Total segment margin	350	194	575	347
Add (deduct):				
Non-cash loss (gain) from commodity derivatives	1	(12)	4	(8)
Segment margin related to noncontrolling interests of ELG	(6)	(2)	(12)	(3)
Segment margin related to ownership percentage in Ranch JV	3	1	6	2
Adjusted total segment margin	$348	$181	$573	$338

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Three Months Ended June 30, 2014 vs. Three Months Ended June 30, 2013

	Three Months Ended June 30,			
	2014	2013	Change	Percent
Total revenues	$1,178	$639	$539	84 %
Cost of sales	828	445	(383)	86
Total segment margin [1]	350	194	156	80
Operation and maintenance	93	73	(20)	27
General and administrative	54	18	(36)	200
Loss on asset sales, net	—	1	1	100
Depreciation, depletion and amortization	168	68	(100)	147
Operating income	35	34	1	3
Income from unconsolidated affiliates	47	31	16	52
Interest expense, net	(78)	(41)	(37)	90
Loss on debt refinancing	—	(7)	7	100
Other income and deductions, net	(7)	(7)	—	—
Income before income taxes	(3)	10	(13)	130
Income tax expense (benefit)	1	(1)	(2)	200
Net (loss) income	(4)	11	(15)	136
Net income attributable to noncontrolling interest	(4)	(1)	(3)	300
Net (loss) income attributable to Regency Energy Partners LP	$(8)	$10	$(18)	180
Gathering and processing segment margin	$269	$145	$124	86
Non-cash loss (gain) from commodity derivatives	1	(12)	13	108
Segment margin related to noncontrolling interests of ELG	(6)	(2)	(4)	200
Segment margin related to ownership percentage in Ranch JV	3	1	2	200
Adjusted gathering and processing segment margin	267	132	135	102
Contract services segment margin [2]	63	49	14	29
Natural resources segment margin	20	—	20	100
Corporate segment margin	2	4	(2)	50
Intersegment eliminations [2]	(4)	(4)	—	—
Adjusted total segment margin	$348	$181	$167	92 %

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

(2) Contract Services segment margin includes intersegment revenues of $4 million for the three months ended June 30, 2014 and 2013. These intersegment revenues were eliminated upon consolidation.

Net Income Attributable to Regency Energy Partners LP. We had a net loss of $8 million for the three months ended June 30, 2014 compared to net income of $10 million for the three months ended June 30, 2013. The major components of this change were as follows:

- $156 million increase in total segment margin primarily due to a $120 million contribution in segment margin from the PVR and Hoover acquisitions and increased volumes in south and west Texas and north Louisiana in our Gathering and Processing segment including;
- $16 million increase in income from unconsolidated subsidiaries primarily related to our investment in Lone Star due to an increase in volumes fractionated as Lone Star Fractionator II was commissioned in late 2013 and an increase in volumes transported in west Texas; offset by

- $100 million increase in depreciation, depletion and amortization primarily due to the completion of various organic growth projects and an increase associated with the PVR and Hoover acquisitions;

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- $37 million increase in interest expense, net primarily due to the issuance of $900 million 5.875% senior notes issued in February 2014 and $15 million in interest expense related to the senior notes assumed in the PVR Acquisition;
- $36 million increase in general and administrative expenses primarily due to higher acquisitions costs and higher salaries, and
- $20 million increase in operation and maintenance expense primarily due to increases in plant and pipeline maintenance and materials expenses, employee expenses, and ad valorem taxes primarily due to organic growth in south and west Texas.

Adjusted Total Segment Margin. Adjusted total segment margin increased to $348 million in the three months ended June 30, 2014 from $181 million in the three months ended June 30, 2013. The major components of this change were as follows:

- Adjusted Gathering and Processing segment margin increased to $267 million during the three months ended June 30, 2014 from $132 million for the three months ended June 30, 2013 primarily due to volume growth in south and west Texas and north Louisiana, including a $101 million contribution from the PVR and Hoover acquisitions. Total Gathering and Processing throughput increased to 4,895,000 MMBtu/d during the three months ended June 30, 2014, including 2,353,000 MMbtu/d from the PVR and Hoover acquisitions, from 2,178,000 MMBtu/d during the three months ended June 30, 2013. Total NGL gross production increased to 134,000 Bbls/d during the three months ended June 30, 2014 from 89,100 Bbls/d during the three months ended June 30, 2013;
- Natural Resources segment margin was $20 million during the three months ended June 30, 2014. Coal royalty tonnage for the same period was 4,011,000, for an average royalty per ton of $3.75; and
- Contract Services segment margin increased to $63 million during the three months ended June 30, 2014 from $49 million for the three months ended June 30, 2013. As of June 30, 2014 and 2013, total revenue generating horsepower was 1,187,000 and 938,000, inclusive of 47,000 and 41,000, respectively, of revenue generating horsepower utilized by our Gathering and Processing segment.

Operation and Maintenance. Operation and maintenance expense increased to $93 million in the three months ended June 30, 2014 from $73 million during the three months ended June 30, 2013. The change was primarily due to the following:

- $7 million increase in employee expenses due to higher salaries and benefits expenses related to an increase in headcount from the PVR and Hoover acquisitions;
- $6 million increase in pipeline and plant maintenance and materials expenses primarily due to organic growth in south and west Texas as well as the PVR and Hoover acquisitions; and
- $5 million increase in ad valorem tax expenses due to higher total taxable values of assets related to the PVR and Hoover acquisitions.

General and Administrative. General and administrative expense increased to $54 million in the three months ended June 30, 2014 from $18 million in the three months ended June 30, 2013 primarily due to a $25 million increase in acquisition costs and a $7 million increase in employee costs due to additional employees from the PVR and Hoover acquisitions.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased to $168 million in the three months ended June 30, 2014 from $68 million in the three months ended June 30, 2013, primarily due to the completion of various organic growth projects since July 2013 and assets acquired from PVR and Hoover.

Income from Unconsolidated Affiliates. Income from unconsolidated affiliates increased to $47 million for the three months ended June 30, 2014 from $31 million for the three months ended June 30, 2013. The schedule below summarizes the components of income from unconsolidated affiliates and our ownership interest for the three months ended June 30, 2014 and 2013, respectively:

	Three Months Ended June 30, 2014						
	HPC	MEP	Lone Star	Ranch JV	Aqua - PVR	Coal Handling	Total
Net income (loss)	$16	$23	$89	$8	$(2)	$1	
Ownership interest	49.99 %	50 %	30 %	33.33 %	51 %	50 %	
	8	12	27	3	(1)	—	

Share of unconsolidated affiliates' net income (loss)							
Less: Amortization of excess fair value of unconsolidated affiliates	(2)	—	—	—	—	—	
Income (loss) from unconsolidated affiliates	$6	$12	$27	$3	$(1)	$—	$47

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

HPC's net income decreased to $16 million for the three months ended June 30, 2014 from $18 million for the three months ended June 30, 2013, primarily due to the expiration of certain contracts that were not renewed. MEP's net income increased to $23 million for the three months ended June 30, 2014 from $21 million for the three months ended June 30, 2013. Lone Star's net income increased to $89 million for the three months ended June 30, 2014 from $44 million for the three months ended June 30, 2013, primarily due to an increase in volumes fractionated as Lone Star Fractionator II was commissioned in late 2013, and increase in volumes transported from west Texas, and an increase in marketing net income due to a more favorable price environment in early 2014. These increases were offset by a decrease in earnings attributable to our refinery off-gas fractionator in Geismar, LA due to the expiration of a major refinery contract in June 2013.

The following table presents operational data for each of our unconsolidated affiliates for the three months ended June 30, 2014 and 2013:

		Three Months Ended June 30,	
	Operational data	2014	2013
HPC	Throughput (MMBtu/d)	664,740	657,950
MEP	Throughput (MMBtu/d)	1,197,413	1,263,734
Lone Star	NGL Transportation — Total Volumes (Bbls/d)	214,518	162,552
	Refinery — Geismar Throughput (Bbls/d)	12,724	14,748
	Fractionation — Throughput Volume (Bbls/d)	176,691	86,947
Ranch JV	Throughput (MMBtu/d)	139,908	68,522

Interest Expense, Net. Interest expense, net increased to $78 million for the three months ended June 30, 2014 from $41 million for the three months ended June 30, 2013, primarily due to the interest related to our $400 million 5.75% senior notes issued in September 2013 and $900 million 5.875% senior notes issued in February 2014, and $15 million in interest expense related to the senior notes assumed in the PVR Acquisition. In the three months ended June 30, 2013, we incurred a $7 million loss on debt refinancing related to the redemption at $163 million of all our outstanding 9.375% senior notes due 2016 for $178 million in cash, inclusive of accrued and unpaid interest of $7 million and other fees and expenses.

Other Income and Deductions, Net. Other income and deductions were $7 million for the three months ended June 30, 2014 and 2013.

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Six Months Ended June 30, 2014 vs. Six Months Ended June 30, 2013

	Six Months Ended June 30,			
	2014	2013	Change	Percent
Total revenues	$2,041	$1,179	$862	73 %
Cost of sales	1,466	832	(634)	76
Total segment margin [1]	575	347	228	66
Operation and maintenance	171	142	(29)	20
General and administrative	87	51	(36)	71
(Gain) loss on asset sales, net	(2)	2	4	200
Depreciation, depletion and amortization	262	133	(129)	97
Operating income	57	19	38	200
Income from unconsolidated affiliates	90	66	24	36
Interest expense, net	(134)	(78)	(56)	72
Loss on debt refinancing, net	—	(7)	7	100
Other income and deductions, net	(5)	(21)	16	76
Income (loss) before income taxes	8	(21)	29	138
Income tax benefit	—	(3)	3	100
Net income (loss)	8	(18)	26	144
Net income attributable to noncontrolling interest	(7)	(1)	(6)	600
Net income (loss) attributable to Regency Energy Partners LP	$1	$(19)	$20	105
Gathering and processing segment margin	$435	$248	$187	75
Non-cash loss (gain) from commodity derivatives	4	(8)	12	150
Segment margin related to noncontrolling interests of ELG	(12)	(3)	(9)	300
Segment margin related to ownership percentage in Ranch JV	6	2	4	200
Adjusted gathering and processing segment margin	433	239	194	81
Contract services segment margin [2]	119	97	22	23
Natural resources segment margin	22	—	22	100
Corporate segment margin	7	9	(2)	22
Intersegment eliminations [2]	(8)	(7)	(1)	14
Adjusted total segment margin	$573	$338	$235	70 %

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

(2) Contract Services segment margin includes intersegment revenues of $8 million and $7 million for the six months ended June 30, 2014 and 2013, respectively. These intersegment revenues were eliminated upon consolidation.

Net Income Attributable to Regency Energy Partners LP. We had a net income of $1 million for the six months ended June 30, 2014 compared to net loss of $19 million for the six months ended June 30, 2013. The major components of this change were as follows:

- $228 million increase in total segment margin primarily due to increased volumes in south and west Texas and north Louisiana in our Gathering and Processing segment including a $139 million contribution in segment margin from the PVR and Hoover acquisitions;
- $24 million increase in income from unconsolidated subsidiaries primarily related to our investment in Lone Star due to an increase in volumes fractionated as Lone Star Fractionator II was commissioned in late 2013 and an increase in volumes transported in west Texas; and

- $16 million increase in other income and deductions primarily due to a decrease in the non-cash mark-to-market loss on the embedded derivative related to the Series A preferred units for the six months ended June 30, 2014 compared to the loss for the six months ended June 30, 2013; offset by

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- $129 million increase in depreciation, depletion and amortization primarily due to the completion of various organic growth projects and an increase associated with the PVR and Hoover acquisitions;
- $56 million increase in interest expense, net primarily due to the issuance of $600 million 4.5% senior notes issued in April 2013, $400 million 5.75% senior notes issued in September 2013, $900 million 5.875% senior notes issued in February 2014, and $19 million in interest expense related to the senior notes assumed in the PVR Acquisition;
- $36 million increase in general and administrative expense primarily due to higher acquisitions costs; and
- $29 million increase in operation and maintenance expense primarily due to increases in plant and pipeline maintenance and materials expenses and employee expenses primarily due to organic growth in south and west Texas, including $20 million related to the PVR and Hoover acquisitions.

Adjusted Total Segment Margin. Adjusted total segment margin increased to $573 million in the six months ended June 30, 2014 from $338 million in the six months ended June 30, 2013. The major components of this change were as follows:

- Adjusted Gathering and Processing segment margin increased to $433 million during the six months ended June 30, 2014 from $239 million for the six months ended June 30, 2013 primarily due to volume growth in south and west Texas and north Louisiana, including a $117 million contribution from the PVR and Hoover acquisitions. Total Gathering and Processing throughput increased to 3,785,000 MMBtu/d during the six months ended June 30, 2014, including 1,362,000 MMbtu/d from the PVR and Hoover acquisitions, from 2,064,000 MMBtu/d during the six months ended June 30, 2013. Total NGL gross production increased to 116,000 Bbls/d during the six months ended June 30, 2014 from 86,000 Bbls/d during the six months ended June 30, 2013;
- Natural Resources segment margin was $22 million from March 21, 2014 (the date of acquisition) to June 30, 2014. Coal royalty tonnage for the same period was 4,483,000, for an average royalty per ton of $3.80; and
- Contract Services segment margin increased to $119 million during the six months ended June 30, 2014 from $97 million for the six months ended June 30, 2013. As of June 30, 2014 and 2013, total revenue generating horsepower was 1,187,000 and 938,000, inclusive of 47,000 and 41,000, respectively, of revenue generating horsepower utilized by our Gathering and Processing segment.

Operation and Maintenance. Operation and maintenance expense increased to $171 million in the six months ended June 30, 2014 from $142 million during the six months ended June 30, 2013. The change was primarily due to the following:

- $12 million increase in pipeline and plant maintenance and materials expenses primarily due to organic growth in south and west Texas as well as the PVR and Hoover acquisitions;
- $7 million increase in utilities expenses primarily due to additional facilities from the PVR and Hoover acquisitions;
- $7 million increase in ad valorem taxes due to higher total taxable values of assets related to assets acquired from PVR and Hoover; and
- $5 million increase in employee expenses due to higher salaries and benefits expenses due to an increase in headcount related to the PVR and Hoover acquisitions.

General and Administrative. General and administrative expense increased to $87 million in the six months ended June 30, 2014 from $51 million in the three months ended June 30, 2013 primarily due to a $37 million increase in acquisition costs.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased to $262 million in the six months ended June 30, 2014 from $133 million in the six months ended June 30, 2013, primarily due to the completion of various organic growth projects since July 2013and assets acquired from PVR and Hoover.

Income from Unconsolidated Affiliates. Income from unconsolidated affiliates increased to $90 million for the six months ended June 30, 2014 from $66 million for the six months ended June 30, 2013. The schedule below summarizes the components of income from unconsolidated affiliates and our ownership interest for the six months ended June 30, 2014 and 2013, respectively:

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	Six Months Ended June 30, 2014						
	HPC	MEP	Lone Star	Ranch JV	Aqua - PVR	Coal Handling	Total
Net income (loss)	$31	$44	$172	$14	$(2)	$1	
Ownership interest	49.99 %	50 %	30 %	33.33 %	51 %	50 %	
Share of unconsolidated affiliates' net income (loss)	16	22	51	5	(1)	—	
Less: Amortization of excess fair value of unconsolidated affiliates	(3)	—	—	—	—	—	
Income (loss) from unconsolidated affiliates	$13	$22	$51	$5	$(1)	$—	$90

	Six Months Ended June 30, 2013					
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch	Total
Net income (loss)	$38	$42	$99	$1	$(1)	
Ownership interest	49.99 %	50 %	30 %	33.33 %	51 %	
Share of unconsolidated affiliates' net income	19	20	30	—	—	
Less: Amortization of excess fair value of unconsolidated affiliates	(3)	—	—	—	—	
Income from unconsolidated affiliates	$16	$20	$30	$—	$—	$66

HPC's net income decreased to $31 million for the six months ended June 30, 2014 from $38 million for the six months ended June 30, 2013, primarily due to the expiration of certain contracts that were not renewed, as well as a customer declaring bankruptcy on April 1, 2013. MEP's net income increased to $44 million for the six months ended June 30, 2014 from $42 million for the six months ended June 30, 2013. Lone Star's net income increased to $172 million for the six months ended June 30, 2014 from $99 million for the six months ended June 30, 2013, primarily due to an increase in volumes fractionated as Lone Star Fractionator II was commissioned in late 2013, and increase in volumes transported west Texas, and an increase in marketing net income due to a more favorable price environment in early 2014. These increases were offset by a decrease in earnings attributable to our refinery off-gas fractionator in Geismar, LA due to the expiration of a major refinery contract in June 2013.

The following table presents operational data for each of our unconsolidated affiliates for the six months ended June 30, 2014 and 2013:

		Six Months Ended June 30,	
	Operational data	2,014	2013
HPC	Throughput (MMBtu/d)	639,034	685,877
MEP	Throughput (MMBtu/d)	1,232,332	1,363,020
Lone Star	NGL Transportation — Total Volumes (Bbls/d)	199,300	158,023
	Refinery — Geismar Throughput (Bbls/d)	12,002	15,983
	Fractionation — Throughput Volume (Bbls/d)	158,320	69,072
Ranch JV	Throughput (MMBtu/d)	130,016	60,802

Interest Expense, Net. Interest expense, net increased to $134 million for the six months ended June 30, 2014 from $78 million for the six months ended June 30, 2013, primarily due to the interest related to our $600 million 4.5% senior notes issued April 30, 2013 our $400 million 5.75% senior notes issued in September 2013, and our $900 million 5.875% senior notes issued in February 2014, and $19 million in interest expense related to the senior notes assumed in the PVR Acquisition.

Other Income and Deductions, Net. Other income and deductions, net increased to a loss of $5 million in the six months ended June 30, 2014 from a loss of $21 million in the six months ended June 30, 2013, primarily due to a decrease in the non-cash mark-to-market of the embedded derivative related to the Series A preferred units in the six months ended June 30, 2014 comparable to the six months ended June 30, 2013.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

In addition to the information set forth in this report, further information regarding our critical accounting policies and estimates is included in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2013.

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OTHER MATTERS

Information regarding our commitments and contingencies is included in Note 8 – Commitments and Contingencies to the condensed consolidated financial statements included in Item 1 of this report.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

We expect our sources of liquidity to include:

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

We expect our 2014 capital expenditures, including expenditures related to the recently acquired PVR and Eagle Rock assets, to be as follows:

	2014
Growth Capital Expenditures	
Gathering and Processing	$850
NGL Services	100
Contract Services	300
Total	$1,250
Maintenance Capital Expenditures; including our proportionate share related to our unconsolidated affiliates	$90

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

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

We had a working capital deficit of $138 million at June 30, 2014 compared to a working capital deficit of $75 million at December 31, 2013. The increase in the working capital deficit was primarily due to the $175 million accrued capital contribution to MEP, offset by a $95 million increase in trade accounts receivable, net of trade accounts payable, and a $31 million increase in cash.

Cash Flows from Operating Activities. Net cash flows provided by operating activities increased to $277 million in the six months ended June 30, 2014 from $195 million in the six months ended June 30, 2013, primarily as a result of an increase in segment margin of $228 million due to volume growth in south and west Texas and north Louisiana, and the PVR and Hoover acquisitions.

Cash Flows used in Investing Activities. Net cash flows used in investing activities was $670 million in the six months ended June 30, 2014 compared to cash used in investing activities of $958 million in the six months ended June 30, 2013 primarily due

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to a decrease in acquisitions, net of cash received as more cash was spent for the SUGS Acquisition in April 2013 than in the PVR and Hoover Acquisitions.

Growth Capital Expenditures. Growth capital expenditures are capital expenditures made to acquire additional assets to increase our business, to expand and upgrade existing systems and facilities or to construct or acquire systems or facilities. In the six months ended June 30, 2014, we incurred $443 million of growth capital expenditures, inclusive of contributions to unconsolidated affiliates. Growth capital expenditures for the six months ended June 30, 2014 were primarily related to $232 million for our Gathering and Processing segment, $46 million for our NGL Services segment, $2 million for our Transportation segment, and $163 million for our Contract Services segment.

Maintenance Capital Expenditures. Maintenance capital expenditures are capital expenditures made to replace partially or fully depreciated assets or to maintain the existing operating capacity of our assets and extend their useful lives. In the six months ended June 30, 2014, we incurred $37 million of maintenance capital expenditures.

Cash Flows from Financing Activities. Net cash flows provided by financing activities decreased to $424 million in the six months ended June 30, 2014 from cash flow provided by financing activities of $727 million during the same period in 2013 primarily due to higher repayments under the revolving credit facility, an increase in the redemption of senior notes, and an increase in partner distributions, offset by higher proceeds from the issuance of senior notes and common unit offerings.

Capital Resources

Equity Distribution Agreement. In June 2012, we entered into an equity distribution agreement with Citi under which we may offer and sell common units having an aggregate offering price of up to $200 million, from time to time through Citi, as sales agent for the Partnership. Sales of these units made from time to time under the equity distribution agreement were made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices, in block transactions, or as otherwise agreed upon by us and Citi. We used the net proceeds from the sale of these common units for general partnership purposes. During the six months ended June 30, 2014, we received net proceeds of $34 million from common units sold pursuant to this equity distribution agreement and no amounts remained available to be issued under this agreement and it is no longer effective.

In May 2014, we entered into an equity distribution agreement with Barclays under which we may offer and sell common units having an aggregate offering price of up to $400 million, from time to time through Barclays, as sales agent for the Partnership. Sales of these units made from time to time under the equity distribution agreement will be made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices, in block transactions, or as otherwise agreed upon by us and Barclays. We may also sell common units to Barclays as principal for its own account at a price agreed upon at the time of sale. Any sale of common units to Barclays as principal would be pursuant to the terms of a separate agreement between us and Barclays. We intend to use the net proceeds from the sale of these units for general partnership purposes. During the six months ended June 30, 2014, we received net proceeds of $31 million from common units sold pursuant to this equity distribution agreement.

Common Units Sold. In June 2014, we sold 14.4 million common units to ETE Common Holdings for proceeds of $400 million. Proceeds from the issuance were used to pay down borrowings on our revolving credit facility, to redeem certain senior notes of the Partnership and for general partnership purposes. In July 2014, we sold 16.5 million common units to ETE Common Holdings for proceeds of $400 million, and issued 8.2 million common units to Eagle Rock in connection with the Eagle Rock Midstream Acquisition.

Revolver Amendment. In February 2014, RGS entered into the First Amendment to the Credit Agreement to, among other things, expressly permit the pending PVR and Eagle Rock Midstream acquisitions, and to increase the commitment to $1.5 billion and increase the uncommitted incremental facility to $500 million. The amendment will specifically allow us to assume the series of PVR senior notes that mature prior to our Credit Agreement.

Senior Notes. In February 2014, we and Finance Corp. issued $900 million of senior notes that mature on March 1, 2022 (the "2022 Notes"). The 2022 Notes bear interest at 5.875% with interest payable semi-annual in arrears on September 1 and March 1. At any time prior to December 1, 2021, we may redeem some or all of the notes at 100% of the principal amount thereof, plus a "make-whole" redemption price and accrued and unpaid interest, if any, to the redemption date. On or after, December 1, 2021, we may redeem some or all of the notes at a redemption price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date. If we undergo certain change of control transactions, we may be required to offer to purchase the notes from holders. The 2022 Notes are guaranteed by our existing consolidated subsidiaries except Finance Corp and ELG. The 2022 Notes will rank equally in right of payment with all of our existing and future senior unsecured debt, including our other outstanding Senior Notes, and contain substantially the same covenants as our other existing Senior Notes.

In March 2014, in connection with the PVR Acquisition, we assumed $1.2 billion in aggregate principal amount of PVR's outstanding senior notes, consisting of $300 million of 8.25% senior notes that mature on April 15, 2018, $400 million of 6.5%

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senior notes that mature on May 15, 2021, and $473 million of 8.375% senior notes that mature on June 1, 2020. In April 2014, we redeemed all of the 2018 PVR Notes for $313 million at a price of 104.125% plus accrued and unpaid interest paid to the redemption date. Interest on the 2021 PVR Notes and the 2020 PVR Notes accrue semi-annually on May 15 and November 15 and June 1 and December 1, respectively.

On March 24, 2014, in accordance with our obligations under the indentures governing the 2020 PVR Notes and the 2021 PVR Notes, we commenced change of control offers pursuant to which holders of such notes were entitled to require us to repurchase all or a portion of their notes at a purchase price of 101% of the principal amount thereof, plus accrued and unpaid interest to the repurchase date. The change of control offers for the 2020 PVR Notes and the 2021 PVR Notes expired on April 22, 2014 and, on April 23, 2014, we accepted for purchase less than one million in aggregate principal amount of 2021 PVR Notes.

In July 2014, we exchanged $499 million of 8.375% Senior Notes due 2019 (the “Eagle Rock Notes”) of Eagle Rock and Eagle Rock Energy Finance Corp. for 8.375% Senior Notes due 2019 to be issued by us and Finance Corp. (the “New Partnership Notes”). The New Partnership Notes will have substantially the same economic terms as the outstanding Eagle Rock Notes, including interest rate, interest payment dates, optional redemption terms and maturity. The New Partnership Notes will rank equally with the Partnership’s existing Senior Notes.

In July 2014, we and Finance Corp. issued $700 million of senior notes that mature on October 1, 2022 (the “October 2022 Notes”). The October 2022 Notes bear interest at 5% with interest payable semi-annual in arrears on October 1 and April 1, beginning April 1, 2015. At any time prior to July 1, 2022, we may redeem some or all of the notes at 100% of the principal amount thereof, plus a “make-whole” redemption price and accrued and unpaid interest, if any, to the redemption date. On or after, July 1, 2022, we may redeem some or all of the notes at a redemption price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date. If we undergo certain change of control transactions, we may be required to offer to purchase the notes from holders. The October 2022 Notes are guaranteed by substantially all of our subsidiaries. In accordance with the terms of the October 2022 Notes, the acquired Eagle Rock entities will become guarantors of the October 2022 Notes within 20 business days of their guarantee of our obligations under the revolving credit facility, which is required to occur within 30 days of the closing of the Eagle Rock Midstream Acquisition. The October 2022 Notes will rank equally in right of payment with all of our existing and future senior unsecured debt, including our other outstanding Senior Notes, and contain substantially the same covenants as our other existing Senior Notes.

In July 2014, we redeemed $83 million of the $473 million outstanding 2020 PVR Notes for $91 million, including $8 million of accrued interest and redemption premium.

Compliance with Loan Covenants. At June 30, 2014, we were in compliance with all covenants under the Credit Agreement and the indentures governing the Senior Notes.

Cash Distributions from Unconsolidated Affiliates. The following table summarizes the cash distributions from unconsolidated affiliates for the six months ended June 30, 2014 and 2013:

	Six Months Ended June 30,	
	2014	2013
HPC	$21	$30
MEP	37	38
Lone Star	57	40
Ranch JV	1	—
	$116	$108

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Contractual Obligations. The following table summarizes our contractual cash obligations as of June 30, 2014:

	Payments Due By Period				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (including interest) (1)	$7,527	$308	$617	$2,014	$4,588
Operating leases (5)	61	7	14	8	32
Purchase obligations (2)	192	192	—	—	—
Natural gas and midstream activities (4)	9	8	1	—	—
Distributions and redemption of Series A Preferred Units (3)	98	3	6	7	82
Related party cash obligations	88	5	11	8	64
Contingency payments (6)	3	—	2	1	—
Asset retirement obligations	3	—	—	—	3
Total (7)	$7,981	$523	$651	$2,038	$4,769

(1) Assumes a constant LIBOR interest rate of .0554% plus applicable margin (2.50% as of June 30, 2014) for our revolving credit facility. The principal of our outstanding senior notes ($4.57 billion) bears a weighted average interest rate of 6.14%.

(2) Excludes physical and financial purchases of natural gas, NGLs, and other commodities due to the nature of both the price and volume components of such purchases, which vary on a daily and monthly basis. Additionally, we do not have contractual commitments for fixed price and/or fixed quantities of any material amount.

(3) Assumes that the Series A Preferred Units are redeemed for cash on September 2, 2029, and an annual distribution of $3 million.

(4) Commitments for natural gas midstream activities related to firm transportation agreements.

(5) Primarily relates to equipment, building leases, and leases of coal reserve-based properties which we sublease, or intend to sublease, to third parties.

(6) Represent the accreted contingency payments related to the purchase price for coal reserves in Northern Appalachia. The undiscounted contingency payments are $5.2 million.

(7) Excludes deferred tax liabilities of $20 million as the amount payable by period cannot be readily estimated in light of net operating loss carryforwards and future business plans for the entity that generated the deferred tax liability.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

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

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

positions with derivative contracts are prohibited under our risk management policy.
We have swap contracts that settle against certain NGLs, condensate and natural gas market prices.

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The following table sets forth certain information regarding our hedges outstanding at June 30, 2014. The relevant index price that we pay for NGLs is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas, as reported by the Oil Price Information Service. The relevant index price for natural gas is NYMEX on the pricing dates as defined by the swap contracts. The relevant index for WTI is the monthly average of the daily price of WTI as reported by the NYMEX.

June 30, 2014

Period	Underlying	Notional Volume/ Amount		We Pay	We Receive Weighted Average Price		Fair Value Asset/ (Liability) (in millions)	Effect of Hypothetical Change in Index*
July 2014 – December 2015	Propane	(790)	MBbls	Index	$ 1.05	/gallon	(1)	4
July 2014 – December 2014	Normal Butane	(294)	MBbls	Index	$ 1.34	/gallon	1	2
July 2014 – December 2015	West Texas Intermediate Crude	(665)	MBbls	Index	$ 94.15	/Bbl	(4)	7
July 2014 – December 2015	Natural Gas	(20,553,000)	MMbtu	Index	$ 4.15	/MMBtu	(5)	9
					Total Fair Value		$(9)	

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

Item 4. Controls and Procedures

Disclosure controls. At the end of the period covered by this report, an evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rule 13a–15(e) and 15d–15(e) of the Exchange Act). Based on management's evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective in achieving that level of reasonable assurance as of June 30, 2014.

Internal control over financial reporting. We closed the Hoover Acquisition on February 3, 2014 and the PVR Acquisition on March 21, 2014. We have begun the evaluation of the internal control structures of these entities, and we expect that evaluation to continue during the remainder of 2014. In recording these acquisitions, we followed our normal accounting procedures and internal controls. Our management also reviewed the operations of these entities from the date of acquisition that are included in our results of operations for the three months ended June 30, 2014. None of the changes resulting from the Hoover Acquisition and the PVR Acquisition were in response to any identified deficiency or weakness in our internal control over financial reporting other than changes resulting from these acquisitions.

There have been no changes in our internal controls, other than those resulting from the Hoover and PVR acquisitions, over financial reporting (as defined in Rule 13(a)–15(f) or Rule 15d–15(f) of the Exchange Act) during the three months ended June 30, 2014 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

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PART II – OTHER INFORMATION

Item 1. Legal Proceedings

The information required for this item is provided in Note 8, Commitments and Contingencies, included in the notes to the unaudited condensed consolidated financial statements included under Part I, Item 1, which information is incorporated by reference into this item.

Item 1A. Risk Factors

For information regarding risk, uncertainties and assumptions, see Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2013 and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2014. There are no material changes from the risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2013 and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2014.

Item 4. Mine Safety Disclosures

Not applicable.

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Item 6. Exhibits

Exhibit Number	Description	Incorporated by Reference from Form	Date Filed and File No
10.1	Common Unit Purchase Agreement, dated June 4, 2014, by and between Regency Energy Partners LP and ETE Common Holdings, LLC.	8-K	June 5, 2014 001-35262
10.2	Registration Rights Agreement, dated June 4, 2014, by and between Regency Energy Partners LP and ETE Common Holdings, LLC.	8-K	June 5, 2014 001-35262
10.3	Guaranty, dated June 12, 2014, by Regency Energy Partners LP in favor of Midcontinent Express Pipeline LLC.	8-K	June 18, 2014 001-35262
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	*	
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	*	
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	**	
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	**	
101.INS	XBRL Instance Document.	*	
101.SCH	XBRL Taxonomy Extension Schema Document.	*	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.	*	
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.	*	
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.	*	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.	*	

*Filed herewith.
*Furnished herewith.

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

REGENCY ENERGY PARTNERS LP
By: Regency GP LP, its general partner
By: Regency GP LLC, its general partner

Date: August 7, 2014

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