Regency Energy Partners LP
Form 10-Q
May 08, 2014
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)

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

For the quarterly period ended March 31, 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 356,547,665 common units and 6,274,483 Class F units outstanding as of May 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
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
EROC	Eagle Rock Energy Partners, L.P.
ETC	Energy Transfer Company, the name assumed by La Grange Acquisition, L.P. for conducting business and shared services, a wholly-owned subsidiary of ETP
ETE	Energy Transfer Equity, L.P.
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.
Ranch JV	Ranch Westex JV LLC

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Name	Definition or Description
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;
- our ability to complete our acquisition of Eagle Rock’s midstream business;
- 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;
- 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 this Quarterly Report on Form 10-Q.

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

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

	March 31, 2014	December 31, 2013
ASSETS		
Current Assets:		
Cash and cash equivalents	$13	$19
Trade accounts receivable, net	446	292
Related party receivables	24	28
Inventories	57	42
Other current assets	20	19
Total current assets	560	400
Property, plant and equipment	8,033	5,050
Less accumulated depreciation and depletion	(712)	(632)
Property, plant and equipment, net	7,321	4,418
Investment in unconsolidated affiliates	2,178	2,097
Other, net of accumulated amortization of debt issuance costs of $26 and $24	84	57
Intangible assets, net of accumulated amortization of $116 and $107	3,568	682
Goodwill	1,486	1,128
TOTAL ASSETS	$15,197	$8,782
LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Drafts payable	$17	$26
Trade accounts payable	393	291
Related party payables	57	69
Accrued interest	94	38
Other current liabilities	108	51
Total current liabilities	669	475
Long-term derivative liabilities	20	19
Other long-term liabilities	49	30
Long-term debt, net	5,564	3,310
Commitments and contingencies		
Series A preferred units, redemption amounts of $38 and $38	32	32
Partners' capital and noncontrolling interest:		
Common units	7,835	3,886
Class F units	148	146
General partner interest	783	782
Total partners' capital	8,766	4,814
Noncontrolling interest	97	102
Total partners' capital and noncontrolling interest	8,863	4,916
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$15,197	$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 March 31, 2014	2013
REVENUES		
Gas sales, including related party amounts of $13 and $5	$335	$167
NGL sales, including related party amounts of $50 and $25	331	235
Gathering, transportation and other fees, including related party amounts of $6 and $7	172	127
Net realized and unrealized loss from derivatives	(13)	(3)
Other	38	14
Total revenues	863	540
OPERATING COSTS AND EXPENSES		
Cost of sales, including related party amounts of $10 and $9	638	387
Operation and maintenance	78	69
General and administrative	33	33
(Gain) loss on asset sales, net	(2)	1
Depreciation, depletion and amortization	94	65
Total operating costs and expenses	841	555
OPERATING INCOME (LOSS)	22	(15)
Income from unconsolidated affiliates	43	35
Interest expense, net	(56)	(37)
Other income and deductions, net	2	(14)
INCOME (LOSS) BEFORE INCOME TAXES	11	(31)
Income tax benefit	(1)	(2)
NET INCOME (LOSS)	$12	$(29)
Net income attributable to noncontrolling interest	(3)	—
NET INCOME (LOSS) ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$9	$(29)
Amounts attributable to Series A preferred units	1	2
General partner’s interest, including IDRs	5	2
Beneficial conversion feature for Class F units	2	—
Pre-acquisition loss from SUGS allocated to predecessor equity	—	(24)
Limited partners’ interest in net income (loss)	$1	$(9)
Basic and diluted net income (loss) per common unit:		
Amount allocated to common units	$1	$(9)
Weighted average number of common units outstanding	226,046,232	170,952,804
Basic income (loss) per common unit	$0.00	$(0.06)
Diluted income (loss) per common unit	$0.00	$(0.06)
Distributions per common unit	$0.48	$0.46
Amount allocated to Class F units due to beneficial conversion feature	$2	$—
Total number of Class F units outstanding	6,274,483	—
Income per Class F unit due to beneficial conversion feature	$0.27	$—

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 March 31,	
	2014	2013
Net income (loss)	$12	$(29)
Other comprehensive income (loss)	—	—
Total other comprehensive income (loss)	—	—
Comprehensive income (loss)	12	(29)
Comprehensive income attributable to noncontrolling interest	3	—
Comprehensive income (loss) attributable to Regency Energy Partners LP	$9	$(29)

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)

	Three Months Ended March 31, 2014	2013
OPERATING ACTIVITIES:		
Net income (loss)	$12	$(29)
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	97	67
Income from unconsolidated affiliates	(43)	(35)
Derivative valuation changes	17	18
(Gain) loss on asset sales, net	(2)	1
Unit-based compensation expenses	2	2
Cash flow changes in current assets and liabilities:		
Trade accounts receivable and related party receivables	(21)	(14)
Other current assets and other current liabilities	35	85
Trade accounts payable and related party payables	48	(47)
Distributions of earnings received from unconsolidated affiliates	43	36
Cash flow changes in other assets and liabilities	(1)	(1)
Net cash flows provided by operating activities	187	83
INVESTING ACTIVITIES:		
Capital expenditures	(215)	(273)
Capital contributions to unconsolidated affiliates	(40)	(43)
Distributions in excess of earnings of unconsolidated affiliates	9	16
Acquisitions, net of cash received	(213)	—
Proceeds from asset sales	5	12
Net cash flows used in investing activities	(454)	(288)
FINANCING ACTIVITIES:		
(Repayments) borrowings under revolving credit facility, net	(519)	179
Proceeds from issuances of senior notes	886	—
Debt issuance costs	(16)	—
Drafts payable	(8)	5
Partner distributions and distributions on unvested unit awards	(107)	(83)
Common units issued under equity distribution program, net of costs	34	—
Distributions to Series A preferred units	(1)	(2)
Noncontrolling interest (distributions) contributions	(8)	11
Contributions from previous parent	—	86
Net cash flows provided by financing activities	261	196
Net change in cash and cash equivalents	(6)	(9)
Cash and cash equivalents at beginning of period	19	53
Cash and cash equivalents at end of period	$13	$44
Supplemental cash flow information:		
Accrued capital expenditures	$24	$62
Interest paid, net of amounts capitalized	29	18
Issuance of common units in connection with PVR and Hoover Acquisitions	4,015	—

Accrued capital contribution to unconsolidated affiliate	—	8
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	34	—	—	—	34
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	2	—	—	—	2
Partner distributions and distributions on unvested unit awards	(103)	—	(4)	—	(107)
Noncontrolling interest distributions	—	—	—	(8)	(8)
Net income	2	2	5	3	12
Distributions to Series A Preferred Units	(1)	—	—	—	(1)
Balance - March 31, 2014	$7,835	$148	$783	$97	$8,863

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 March 31, 2013
Revenues:	
Partnership	$349
SUGS	191
Combined	$540
Net loss:	
Partnership	$(5)
SUGS	(24)
Combined	$(29)

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.
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

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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.

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. As of March 31, 2014, no amounts were available to be issued under this agreement. 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 three months ended March 31, 2014, the Partnership received net proceeds of $34 million from common units sold pursuant to this equity distribution agreement.

Units Activity. The change in common and Class F units during the three months ended March 31, 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	10,126	—
Issuance of common units under the equity distribution agreement	1,255,572	—
Issuance of common units in connection with Hoover Acquisition	4,040,471	—
Issuance of common units in connection with PVR Acquisition	140,388,382	—
Balance - March 31, 2014	356,544,783	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

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3. Income (Loss) per Common Unit

The following tables provide a reconciliation of the numerator and denominator of the basic and diluted earnings per common unit computations for the three months ended March 31, 2014 and 2013:

	Three Months Ended March 31,					
	2014			2013		
	Income (Numerator)	Units (Denominator)	Per-Unit Amount	Loss (Numerator)	Units (Denominator)	Per-Unit Amount
Basic income (loss) per unit						
Amount allocated to common units	$1	226,046,232	$0.00	$(9)	170,952,804	$(0.06)
Effect of Dilutive Securities:						
Common unit options	—	22,787		—	—	
Phantom units	—	424,332		—	—	
Series A preferred units	—	2,054,217		—	—	
Diluted income (loss) per unit	$1	228,547,568	$0.00	$(9)	170,952,804	$(0.06)

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 March 31, 2013
Common unit options	12,854
Phantom units	267,820
Series A preferred units	4,665,683

4. Acquisitions

2014

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 PVR 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. From March 21, 2014 through March 31, 2014, revenues and net income attributable to PVR’s operations of $37 million and $2 million, respectively, are included in the Partnership’s results of operations.

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Management's evaluation of the assigned fair values is ongoing. The table below represents a preliminary allocation of the total purchase price:

	At March 21, 2014
Current assets	$150
Property, plant and equipment	2,687
Investment in unconsolidated affiliates	62
Goodwill and intangible assets	3,079
Total assets acquired	$5,978
Current liabilities	166
Long-term debt	1,887
Asset retirement obligations	3
Net assets acquired	$3,922

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. From February 3, 2014 through March 31, 2014, revenues and net income attributable to Hoover's operations of $5 million and $2 million, respectively, are included in the Partnership's results of operations.

Management's evaluation of the assigned fair values is ongoing. The table below represents a preliminary allocation of the total purchase price:

	At February 3, 2014
Current assets	$5
Property, plant and equipment	114
Goodwill and intangible assets	181
Total assets acquired	$300
Current liabilities	5
Asset retirement obligations	2
Net assets acquired	$293

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Pro Forma Results of Operations

The following unaudited pro forma consolidated results of operations for the three months ended March 31, 2014 and 2013 are presented as if the PVR and Hoover acquisitions had been completed on January 1, 2013, and assumes there were no other changes in operations. This pro forma information does not necessarily reflect the actual 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 March 31,	
	2014	2013
Revenues	$1,145	$810
Net loss attributable to the Partnership	(29)	(60)
Basic net loss per Limited Partner unit	$(0.10)	$(0.20)
Diluted net loss per Limited Partner unit	$(0.10)	$(0.20)

The pro forma consolidated results of operations include 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.

The pro forma information is not necessarily indicative of the results of operations that would have occurred had the transactions been made at the beginning of the periods presented or the future results of the combined operations.

Eagle Rock Acquisition. In December, 2013, the Partnership entered into an agreement to purchase Eagle Rock's midstream business (the "Eagle Rock Midstream Acquisition") for approximately $1.3 billion. 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. On April 29, 2014, Eagle Rock's unitholders approved the Eagle Rock Midstream Acquisition. After receiving that approval, all significant closing conditions have been met with the exception of the Federal Trade Commission's ("FTC") antitrust approval. On April 30, 2014, the Partnership and Eagle Rock certified substantial compliance with the FTC in response to its Request for Additional Information and Documentary Material regarding the Eagle Rock Midstream Acquisition. In order to facilitate the FTC's review, Eagle Rock and the Partnership have agreed with the FTC to not close the proposed transaction before June 30, 2014, unless the FTC first closes its investigation.

5. Investment in Unconsolidated Affiliates

As of March 31, 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. The equity income received from the investments in Aqua - PVR and Coal Handling from March 21, 2014 (the acquisition date) to March 31, 2014 was not material. 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. The carrying value of the Partnership's investment in each of the unconsolidated affiliates as of March 31, 2014 and December 31, 2013 is as follows:

	March 31, 2014	December 31, 2013
HPC	$439	$442
MEP	541	548
Lone Star	1,097	1,070
Ranch JV	38	36
Aqua - PVR	51	—

Coal Handling	12	—
Grey Ranch	—	1
Total	$2,178	$2,097

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The following tables summarize the Partnership's investment activities in each of the unconsolidated affiliates for the three months ended March 31, 2014 and 2013:

	Three Months Ended March 31, 2014				
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch
Contributions to unconsolidated affiliates	$—	$—	$27	$—	$—
Distributions from unconsolidated affiliates	(10)	(18)	(25)	—	—
Share of earnings of unconsolidated affiliates' net income (loss)	7	11	25	2	(1)
Amortization of excess fair value of investment	(1)	—	—	—	—

	Three Months Ended March 31, 2013			
	HPC	MEP	Lone Star	Ranch JV
Contributions to unconsolidated affiliates	$—	$—	$27	$1
Distributions from unconsolidated affiliates	(16)	(19)	(17)	—
Share of earnings of unconsolidated affiliates' net income	10	10	16	—
Amortization of excess fair value of investment	(1)	—	—	—

The following tables present selected income statement data for each of the unconsolidated affiliates, on a 100% basis, for the three months ended March 31, 2014 and 2013:

	Three Months Ended March 31, 2014			
	HPC	MEP	Lone Star	Ranch JV
Total revenues	$37	$66	$813	$9
Operating income	18	34	84	7
Net income	15	21	83	6

	Three Months Ended March 31, 2013			
	HPC	MEP	Lone Star	Ranch JV
Total revenues	$40	$65	$358	$3
Operating income	20	34	56	—
Net income	20	21	55	—

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 March 31, 2014, the Partnership had $606 million of outstanding borrowings exposed to variable interest rate risk.

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

The Partnership is exposed to credit risk from its derivative contract counterparties. The Partnership does not require collateral from these counterparties. The Partnership deals primarily with financial institutions when entering into financial derivatives, and utilizes master netting agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximum loss as of March 31, 2014 would be $3 million, which would be reduced by $2 million, due to the netting features. The Partnership has elected to present assets and liabilities under master netting agreements gross on the condensed consolidated balance sheets.

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

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

	Assets		Liabilities	
	March 31, 2014	December 31, 2013	March 31, 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	1	—	—
Embedded derivatives in Series A preferred units	—	—	20	19
Total derivatives	$3	$4	$31	$28

The Partnership's statements of operations for the three months ended March 31, 2014 and 2013 were impacted by derivative instruments activities as follows:

		Three Months Ended March 31,	
		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	$(13)	$(3)
Embedded derivatives in Series A preferred units	Other income & deductions, net	(1)	(14)
		$(14)	$(17)

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7. Long-term Debt

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

	March 31, 2014	December 31, 2013
Senior notes	$4,873	$2,800
Revolving loans	606	510
Unamortized premium and discounts	85	—
Long-term debt	$5,564	$3,310
Availability under revolving credit facility:		
Total credit facility limit	$1,500	$1,200
Revolving loans	(606)	(510)
Letters of credit	(21)	(14)
Total available	$873	$676

Long-term debt maturities as of March 31, 2014 for each of the next five years are as follows:

Years Ending December 31,	Amount
2014 (remainder)	$—
2015	—
2016	—
2017	—
2018	900
Thereafter	4,579
Total *	$5,479

* Excludes a $99 million unamortized premium on the PVR senior notes assumed by the Partnership and a $14 million unamortized discount on the 2022 Notes.

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 2.41% as of March 31, 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-annual 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

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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 April 2014, the Partnership and Finance Corp. commenced a private offer to eligible holders to exchange any and all outstanding 8.375% Senior Notes due 2019 (the “Eagle Rock Notes”) of Eagle Rock and Eagle Rock Energy Finance Corp., of which $550 million in aggregate principal amount is outstanding, for 8.375% Senior Notes due 2019 to be issued by the Partnership and Finance Corp. (the “New Partnership Notes”). The exchange of New Partnership Notes for the Eagle Rock Notes (the “Exchange Offer”) will be conducted on a par-for-par basis, and 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. In addition, holders of Eagle Rock Notes accepted for exchange will receive a cash payment from Eagle Rock for accrued and unpaid interest on such notes from the last interest payment date to, but not including, the settlement date for the Exchange Offer. The New Partnership Notes will rank equally with the Partnership’s existing Senior Notes. This Exchange Offer is contingent upon the closing of the Eagle Rock Midstream Acquisition. On April 28, 2014, the Partnership extended the expiration date of the Exchange Offer to May 28, 2014, unless further extended or terminated.

At March 31, 2014, the Partnership was in compliance with all material covenants under the indentures governing the Senior Notes.

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

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.

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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. In addition, the jury may order interest and attorneys' fees against Regency Marcellus of approximately $10 million. The jury found against Regency Marcellus on its counterclaims. Regency Marcellus has filed appropriate post-trial pleadings and is considering its appeal options.

EROC Shareholder Litigation. Two putative class action lawsuits challenging the Eagle Rock Midstream Acquisition are currently pending in federal district court in Houston, Texas. Both cases name Eagle Rock and its current directors, as well as the Partnership and a subsidiary (collectively, the "Regency Defendants"), 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 enjoin 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. 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 March 31, 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.

	March 31, 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 three months ended March 31, 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

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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 June 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.

Mine Health and Safety Laws. There are numerous mine health and safety laws and regulations applicable to the coal mining industry. However, since we do not operate any mines and do not employ any coal miners, we are not subject to such laws and regulations. Accordingly, we have 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 March 31, 2014 and December 31, 2013, details of the Partnership’s related party receivables and related party payables were as follows:

	March 31, 2014	December 31, 2013
Related party receivables		
ETE and its subsidiaries	$21	$25
HPC	2	1
Ranch JV	1	2
Total related party receivables	$24	$28
Related party payables		
ETE and its subsidiaries	$55	$68
HPC	1	1
Ranch JV	1	—
Total related party payables	$57	$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.

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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 $4 million for the three months ended March 31, 2014 and 2013, respectively.

In conjunction with distributions by the Partnership to the limited and general partner interests, ETE received cash distributions of $17 million and $15 million for the three months ended March 31, 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 $9 million and $14 million during the three months ended March 31, 2014 and 2013, respectively.

Transactions with Lone Star. In 2013, a subsidiary of the Partnership entered into a nineteen month agreement to sell 4,800 Bbls/d of NGLs to Lone Star. For the three months ended March 31, 2014, the Partnership had recorded $17 million in NGL sales under this contract which is included in the related party receivable from ETE and its subsidiaries.

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 and $5 million for the three months ended March 31, 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 months ended March 31, 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.

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- 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, 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 March 31, 2014	2013
External Revenues		
Gathering and Processing	$793	$486
Natural Gas Transportation	—	—
NGL Services	—	—
Contract Services	63	49
Natural Resources	2	—
Corporate	5	5
Eliminations	—	—
Total	$863	$540
Intersegment Revenues		
Gathering and Processing	$—	$—
Natural Gas Transportation	—	—
NGL Services	—	—
Contract Services	4	3
Natural Resources	—	—
Corporate	—	—
Eliminations	(4)	(3)
Total	$—	$—
Segment Margin		
Gathering and Processing	$166	$104
Natural Gas Transportation	—	—
NGL Services	—	—
Contract Services	56	47
Natural Resources	2	—
Corporate	5	5
Eliminations	(4)	(3)
Total	$225	$153
Operation and Maintenance		
Gathering and Processing	$60	$55
Natural Gas Transportation	—	—
NGL Services	—	—
Contract Services	20	17
Natural Resources	—	—
Corporate	2	—
Eliminations	(4)	(3)
Total	$78	$69

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

	Three Months Ended March 31,	
	2014	2013
Total segment margin	$225	$153
Operation and maintenance	(78)	(69)
General and administrative	(33)	(33)
Gain (loss) on asset sales, net	2	(1)
Depreciation, depletion and amortization	(94)	(65)
Income from unconsolidated affiliates	43	35
Interest expense, net	(56)	(37)
Other income and deductions, net	2	(14)
Income (loss) before income taxes	$11	$(31)

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

Total Assets	March 31, 2014	December 31, 2013
Gathering and Processing	$10,493	$4,748
Natural Gas Transportation	982	991
NGL Services	1,097	1,070
Contract Services	1,953	1,897
Natural Resources	560	—
Corporate	112	76
Total	$15,197	$8,782

Investment in Unconsolidated Affiliates	March 31, 2014	December 31, 2013
Gathering and Processing	$89	$36
Natural Gas Transportation	980	991
NGL Services	1,097	1,070
Natural Resources	12	—
Total	$2,178	$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 $2 million was recorded in general and administrative expense for the three months ended March 31, 2014 and 2013.

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 three months ended March 31, 2014:

Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at beginning of period	982,242	$23.16
Service condition grants	710,791	25.97
Vested service condition	(1,126)	24.19
Forfeited service condition	(42,585)	24.64
Outstanding at end of period	1,649,322	$24.33

The Partnership expects to recognize $33 million of compensation expense related to non-vested phantom units over a weighted-average period of 3.9 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 March 31, 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	$—	$—	$—	$2	$2	$—
NGLs	3	3	—	2	2	—
Total Assets	$3	$3	$—	$4	$4	$—
Liabilities						
Commodity Derivatives:						
Natural Gas	$8	$8	$—	$4	$4	$—
NGLs	1	1	—	4	4	—
Condensate	2	2	—	1	1	—
Embedded derivatives in Series A preferred units	20	—	20	19	—	19
Total Liabilities	$31	$11	$20	$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	March 31, 2014
Credit Spread	4.15%
Volatility	22.55%

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

The following table presents the changes in Level 3 derivatives measured on a recurring basis for the three months ended March 31, 2014. There were no transfers between the fair value hierarchy levels for the three months ended March 31, 2014.

	Embedded Derivatives in Series A Preferred Units
Net liability balance at December 31, 2013	$19
Change in fair value	1
Net liability balance at March 31, 2014	$20

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 March 31, 2014 were $5.1 billion and $4.87 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.

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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.
RECENT DEVELOPMENTS.
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 approximately $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.

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.

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.

Eagle Rock Acquisition. In December, 2013, we entered into an agreement to purchase Eagle Rock's midstream business for approximately $1.3 billion. 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. On April 29, 2014, Eagle Rock's unitholders approved the Eagle Rock Midstream Acquisition. After receiving that approval, all significant closing conditions have been met with the exception of the Federal Trade Commission's ("FTC") antitrust approval. On April 30, 2014, we and Eagle Rock certified substantial compliance with the FTC in response to its Request for Additional Information and Documentary Material regarding the Eagle Rock Midstream Acquisition. In order to facilitate the FTC's review, we and Eagle Rock have agreed with the FTC to not close the proposed transaction before June 30, 2014, unless the FTC first closes its investigation.

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

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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.

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'

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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.

EBITDA and adjusted EBITDA do not include interest expense, income tax expense or depreciation 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 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.

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

Reconciliation of "Adjusted EBITDA" to net cash flows provided by operating activities and net income (loss)	Three Months Ended March 31, 2014	2013
Net cash flows provided by operating activities	$187	$83
Add (deduct):		
Depreciation, depletion and amortization, including debt issuance cost amortization and bond premium write-off and amortization	(97)	(67)
Income from unconsolidated affiliates	43	35
Derivative valuation change	(17)	(18)
Gain (loss) on asset sales, net	2	(1)
Unit-based compensation expenses	(2)	(2)
Trade accounts receivable and related party receivables	21	14
Other current assets and other current liabilities	(35)	(85)
Trade accounts payable and related party payables	(48)	47
Distributions of earnings received from unconsolidated affiliates	(43)	(36)
Cash flow changes in other assets and liabilities	1	1
Net income (loss)	12	(29)
Add (deduct):		
Interest expense, net	56	37
Depreciation, depletion and amortization expense	94	65
Income tax benefit	(1)	(2)
EBITDA	161	71
Add (deduct):		
Partnership's interest in unconsolidated affiliates' adjusted EBITDA	75	63
Income from unconsolidated affiliates	(43)	(35)
Non-cash loss from commodity and embedded derivatives	4	18
Other expense, net	8	3
Adjusted EBITDA	$205	$120

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The following tables present reconciliations of net income to adjusted EBITDA for our unconsolidated affiliates, on a 100% basis, and the Partnership's interest in adjusted EBITDA for the three months ended March 31, 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):

	Three Months Ended March 31, 2014				
	HPC	MEP	Lone Star	Ranch JV	Total
Net income	$15	$21	$83	$6	
Add:					
Depreciation and amortization	10	17	25	1	
Interest expense, net	3	13	—	—	
Other expenses, net	—	—	1	—	
Adjusted EBITDA	28	51	109	7	
Ownership interest	49.99 %	50 %	30 %	33.33 %	
Partnership's interest in adjusted EBITDA	$14	$26	$33	$2	$75

	Three Months Ended March 31, 2013				
	HPC	MEP	Lone Star	Ranch JV	Total
Net income	$20	$21	$55	$—	
Add:					
Depreciation and amortization	9	17	20	1	
Interest expense, net	—	13	—	—	
Other expenses, net	—	—	1	—	
Adjusted EBITDA	29	51	76	1	
Ownership interest	49.99 %	50 %	30 %	33.33 %	
Partnership's interest in adjusted EBITDA	$14	$26	$23	$—	$63

The following table presents a reconciliation of total segment margin and adjusted total segment margin to net income (loss) for the three months ended March 31, 2014 and 2013 for the Partnership:

	Three Months Ended March 31,	
	2014	2013
Net income (loss)	$12	$(29)
Add (deduct):		
Operation and maintenance	78	69
General and administrative	33	33
(Gain) loss on asset sales, net	(2)	1
Depreciation, depletion and amortization	94	65
Income from unconsolidated affiliates	(43)	(35)
Interest expense, net	56	37
Other income and deductions, net	(2)	14
Income tax benefit	(1)	(2)
Total segment margin	225	153
Add (deduct):		
Non-cash loss from commodity derivatives	3	4
Segment margin related to noncontrolling interests of ELG	(6)	(2)
Segment margin related to ownership percentage in Ranch JV	3	1
Adjusted total segment margin	$225	$156

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RESULTS OF OPERATIONS

Three Months Ended March 31, 2014 vs. Three Months Ended March 31, 2013

	Three Months Ended March 31,			
	2014	2013	Change	Percent
Total revenues	$863	$540	$323	60 %
Cost of sales	638	387	(251)	65
Total segment margin [1]	225	153	72	47
Operation and maintenance	78	69	(9)	13
General and administrative	33	33	—	—
(Gain) loss on asset sales, net	(2)	1	3	100
Depreciation, depletion and amortization	94	65	(29)	45
Operating income	22	(15)	37	247
Income from unconsolidated affiliates	43	35	8	23
Interest expense, net	(56)	(37)	(19)	51
Other income and deductions, net	2	(14)	16	114
Income (loss) before income taxes	11	(31)	42	135
Income tax benefit	(1)	(2)	(1)	100
Net income (loss)	12	(29)	41	141
Net income attributable to noncontrolling interest	(3)	—	(3)	100
Net income (loss) attributable to Regency Energy Partners LP	$9	$(29)	$38	131
Gathering and processing segment margin	$166	$104	$62	60
Non-cash loss from commodity derivatives	3	4	(1)	25
Segment margin related to noncontrolling interests of ELG	(6)	(2)	(4)	200
Segment margin related to ownership percentage in Ranch JV	3	1	2	100
Adjusted gathering and processing segment margin	166	107	59	55
Contract services segment margin [2]	56	47	9	19
Natural resources segment margin	2	—	2	100
Corporate segment margin	5	5	—	—
Intersegment eliminations [2]	(4)	(3)	(1)	33
Adjusted total segment margin	$225	$156	$69	44 %

(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 and $3 million for the three months ended March 31, 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 $9 million for the three months ended March 31, 2014 compared to net loss of $29 million for the three months ended March 31, 2013. The major components of this change were as follows:

- $72 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 $15 million contribution in segment margin from the PVR and Hoover acquisitions;
- $16 million increase in other income and deductions primarily due to a non-cash mark-to-market gain on the embedded derivative related to the Series A preferred units for the three months ended March 31, 2014, which was a loss for the three months ended March 2013; and

- $8 million increase in income from unconsolidated subsidiaries primarily related to our investment in Lone Star; offset by
- $29 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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- $19 million increase in interest expense, net primarily due to the issuance of $600 million 4.5% senior notes issued in April 2013, $900 million 5.875% senior notes issued in February 2014, and $3 million in interest expense related to the senior notes assumed in the PVR Acquisition; and
- $9 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 $2 million related to the PVR Acquisition.

Adjusted Total Segment Margin. Adjusted total segment margin increased to $225 million in the three months ended March 31, 2014 from $156 million in the three months ended March 31, 2013. The major components of this change were as follows:

- Adjusted Gathering and Processing segment margin increased to $166 million during the three months ended March 31, 2014 from $107 million for the three months ended March 31, 2013 primarily due to volume growth in south and west Texas and north Louisiana, including a $15 million contribution from the PVR and Hoover acquisitions. Total Gathering and Processing throughput increased to 2,662,000 MMBtu/d during the three months ended March 31, 2014, including 359,000 MMbtu/d from the PVR and Hoover acquisitions, from 1,990,000 MMBtu/d during the three months ended March 31, 2013. Total NGL gross production increased to 101,000 Bbls/d during the three months ended March 31, 2014 from 82,700 Bbls/d during the three months ended March 31, 2013;
- Natural Resources segment margin was $2 million from March 21, 2014 (the date of acquisition) to March 31, 2014. Coal royalty tonnage for the same period was 472,000, for an average royalty per ton of $3.89; and
- Contract Services segment margin increased to $56 million during the three months ended March 31, 2014 from $47 million for the three months ended March 31, 2013. As of March 31, 2014 and 2013, total revenue generating horsepower was 1,120,000 and 891,000, inclusive of 47,000 and 38,000, respectively, of revenue generating horsepower utilized by our Gathering and Processing segment.

Operation and Maintenance. Operation and maintenance expense increased to $78 million in the three months ended March 31, 2014 from $69 million during the three months ended March 31, 2013. The change was primarily due to the following:

- $7 million increase in pipeline and plant maintenance and materials expenses primarily due to organic growth in south and west Texas; and
- $2 million increase related to the PVR Acquisition.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased to $94 million in the three months ended March 31, 2014 from $65 million in the three months ended March 31, 2013, primarily due to the completion of various organic growth projects since April 2013, as well as $11 million in depreciation, depletion, and amortization from the PVR and Hoover acquisitions.

Income from Unconsolidated Affiliates. Income from unconsolidated affiliates increased to $43 million for the three months ended March 31, 2014 from $35 million for the three months ended March 31, 2013. The equity received from our investments in Aqua - PVR and Coal Handling from March 21, 2014 (the acquisition date) to March 31, 2014 was not material. The schedule below summarizes the components of income from unconsolidated affiliates and our ownership interest for the three months ended March 31, 2014 and 2013, respectively:

	Three Months Ended March 31, 2014					
	HPC	MEP	Lone Star	Ranch JV	Grey Ranch	Total
Net income	$15	$21	$83	$6	$—	
Ownership interest	49.99 %	50 %	30 %	33.33 %	50 %	
Share of unconsolidated affiliates' net income	7	11	25	2	(1)	
Less: Amortization of excess fair value of unconsolidated affiliates	(1)	—	—	—	—	
Income from unconsolidated affiliates	$6	$11	$25	$2	$(1)	$43

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	Three Months Ended March 31, 2013				
	HPC	MEP	Lone Star	Ranch JV	Total
Net income	$20	$21	$55	$—	
Ownership interest	49.99 %	50 %	30 %	33.33 %	
Share of unconsolidated affiliates' net income	10	10	16	—	
Income from unconsolidated affiliates	$9	$10	$16	$—	$35

HPC's net income decreased to $15 million for the three months ended March 31, 2014 from $20 million for the three months ended March 31, 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 was $21 million for the three months ended March 31, 2014 and 2013. Lone Star's net income increased to $83 million for the three months ended March 31, 2014 from $55 million for the three months ended March 31, 2013, primarily due to an increase in volumes fractionated as Lone Star Fractionator II was commissioned in late 2013 and an increase in Lone Star Marketing's net income due to a more favorable price environment in early 2014.

The following table presents operational data for each of our unconsolidated affiliates for the three months ended March 31, 2014 and 2013:

		Three Months Ended March 31,	
	Operational data	2014	2013
HPC	Throughput (MMBtu/d)	613,041	714,114
MEP	Throughput (MMBtu/d)	1,267,639	1,463,347
Lone Star	NGL Transportation — Total Volumes (Bbls/d)	184,082	153,493
	Refinery — Geismar Throughput (Bbls/d)	11,272	17,232
	Fractionation — Throughput Volume (Bbls/d)	135,359	50,997
Ranch JV	Throughput (MMBtu/d)	120,014	53,443

Interest Expense, Net. Interest expense, net increased to $56 million for the three months ended March 31, 2014 from $37 million for the three months ended March 31, 2013, primarily due to the interest related to our $600 million 4.5% senior notes issued April 30, 2013 in connection with the SUGS Acquisition, the interest related to our $900 million 5.875% senior notes issued in February 2014, and $4 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 gain of $2 million in the three months ended March 31, 2014 from a loss of $14 million in the three months ended March 31, 2013, primarily due to the non-cash mark-to-market of the embedded derivative related to the Series A preferred units in September 2013 changing to a gain for the three months ended March 31, 2014 from a loss for the three months ended March 31, 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.

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;

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- debt offerings; and
- issuance of additional partnership units.

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

	2014
Growth Capital Expenditures	
Gathering and Processing	$860
NGL Services	110
Contract Services	250
Total	$1,220
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 $109 million at March 31, 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 an increase of $34 million in accrued interest related to the assumption of PVR senior notes.

Cash Flows from Operating Activities. Net cash flows provided by operating activities increased to $187 million in the three months ended March 31, 2014 from $83 million in the three months ended March 31, 2013, primarily as a result of an increase in segment margin of $72 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 increased to $454 million in the three months ended March 31, 2014 from cash used in investing activities of $288 million in the three months ended March 31, 2013, primarily as a result of $213 million attributable to the PVR and Hoover acquisitions, offset by a $58 million decrease in capital expenditures.

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 three months ended March 31, 2014, we incurred $188 million of growth capital expenditures, inclusive of contributions to unconsolidated affiliates. Growth capital expenditures for the three months ended March 31, 2014 were primarily related to $83 million for our Gathering and Processing segment, $23 million for our NGL Services segment, $2 million for our Transportation segment, and $80 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 three months ended March 31, 2014, we incurred $22 million of maintenance capital expenditures. In the three months ended March 31, 2013, we incurred $7 million of maintenance capital expenditures, excluding maintenance capital expenditures related to SUGS.

Cash Flows from Financing Activities. Net cash flows provided by financing activities increased to $261 million in the three months ended March 31, 2014 from cash flow provided by financing activities of $196 million during the same period in 2013. The increase is primarily due to proceeds from our issuance of the 2022 Notes used to repay amounts outstanding under the revolving credit facility and issuance of common units under the equity distribution agreement.

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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. As of March 31, 2014, no amounts were available to be issued under this agreement. 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 three months ended March 31, 2014, we received net proceeds of $34 million from common units sold pursuant to this equity distribution agreement.

In March 2014, we filed a registration statement on Form S-3 with the SEC to register for sale up to $400 million in aggregate offering price of our common units. The SEC declared this registration statement effective on April 30, 2014.

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 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% 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 April 2014, we and Finance Corp. commenced a private offer to eligible holders to exchange any and all outstanding 8.375% Senior Notes due 2019 ("Eagle Rock Notes") of Eagle Rock and Eagle Rock Energy Finance Corp., of which $550 million in aggregate principal amount is outstanding, for 8.375% Senior Notes due 2019 to be issued by us and Finance Corp. ("New Partnership Notes"). The exchange of New Partnership Notes for the Eagle Rock Notes ("Exchange Offer") will be conducted on a par-for-par basis, and 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. In addition, holders of Eagle Rock Notes accepted for exchange will receive a cash payment from Eagle Rock for accrued and unpaid interest on such notes from the last interest payment date to, but not including, the settlement date for the Exchange Offer. The New Partnership Notes will rank equally with our existing senior notes. This Exchange Offer is contingent upon the closing of the Eagle Rock Midstream Acquisition. On April 28, 2014, we extended the expiration date on this Exchange Offer to May 28, 2014, unless further extended or terminated.

Compliance with Loan Covenants. At March 31, 2014, we were in compliance with all covenants under the Credit Agreement and the indentures governing the Senior Notes.

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Cash Distributions from Unconsolidated Affiliates. The following table summarizes the cash distributions from unconsolidated affiliates for the three months ended March 31, 2014 and 2013:

	Three Months Ended March 31,	
	2014	2013
HPC	$10	$16
MEP	18	19
Lone Star	25	17
	$53	$52

Contractual Obligations. The following table summarizes our contractual cash obligations as of March 31, 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)	$7,662	$614	$604	$1,791	$4,653
Operating leases (5)	70	9	15	9	37
Purchase obligations (2)	192	192	—	—	—
Natural gas and midstream activities (4)	9	8	1	—	—
Distributions and redemption of Series A Preferred Units (3)	100	3	7	7	83
Related party cash obligations	91	5	11	11	64
Contingency payments (6)	3	—	2	1	—
Asset retirement obligations	3	—	—	—	3
Total (7)	$8,130	$831	$640	$1,819	$4,840

(1) Assumes a constant LIBOR interest rate of .0558% plus applicable margin (2.50% as of March 31, 2014) for our revolving credit facility. The principal of our outstanding senior notes ($4.87 billion) bears a weighted average interest rate of 6.27%.

(2) Represents primarily purchase obligations related to capital expenditures. 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 rights-of-way, 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

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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.

The following table sets forth certain information regarding our hedges outstanding at March 31, 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.

March 31, 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*
April 2014 – December 2015	Propane	(971)	MBbls	Index	$ 1.05	/gallon	(1)	4
April 2014 – December 2014	Normal Butane	(330)	MBbls	Index	$ 1.39	/gallon	3	2
April 2014 – December 2014	West Texas Intermediate Crude	(392)	MBbls	Index	$ 92.68	/Bbl	(2)	4
April 2014 –December 2015	Natural Gas	(23,425,000)	MMbtu	Index	$ 4.09	/MMBtu	(8)	10
					Total Fair Value		$(8)	

* 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 March 31, 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 March 31, 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 March 31, 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. Except as discussed below, there are no material changes from the risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2013.
Risks Related to Our Natural Resources Segment
If our lessees do not manage their operations well or experience financial difficulties, their production volumes and our coal royalties revenues could decrease.
We depend on our lessees to effectively manage their operations on our properties. Our lessees make their own business decisions with respect to their operations, including decisions relating to:

- the method of mining;
- credit review of their customers;
- marketing of the coal mined;
- coal transportation arrangements;
- negotiations with unions;
- employee hiring and firing;
- employee wages, benefits and other compensation;
- permitting;
- surety bonding; and
- mine closure and reclamation.

If our lessees do not manage their operations well, or if they experience financial difficulties, their production could be reduced, which would result in lower coal royalties revenues to us and could have a material adverse effect on our business, results of operations or financial condition.
The coal mining operations of our lessees are subject to numerous operational risks that could result in lower coal royalties revenues.
Our coal royalties revenues are largely dependent on the level of production from our coal reserves achieved by our lessees. The level of our lessees' production is subject to operating conditions or events that may increase our lessees' cost of mining and delay or halt production at particular mines for varying lengths of time and that are beyond their or our control, including:

- the inability to acquire necessary permits;
- changes or variations in geologic conditions, such as the thickness of the coal deposits and the amount of rock embedded in or overlying the coal deposit;
- changes in governmental regulation of the coal industry;
- mining and processing equipment failures and unexpected maintenance problems;
- adverse claims to title or existing defects of title;
- interruptions due to power outages;

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- adverse weather and natural disasters, such as heavy rains and flooding;
- labor-related interruptions;
- employee injuries or fatalities; and
- fires and explosions.

Any interruptions to the production of coal from our reserves could reduce our coal royalties revenues. In addition, our coal royalties revenues are based upon sales of coal by our lessees to their customers. If our lessees do not receive payments for delivered coal on a timely basis from their customers, their cash flow would be adversely affected, which could cause our cash flow to be affected.

We could be negatively impacted by any decline in the market demand for coal.

The domestic demand for, and price of, our coal primarily depend on coal consumption patterns of the domestic electric utility industry. Consumption by the domestic electric utility industry is affected by the demand for electricity, environmental and other governmental regulations, technological developments and the price of competing coal and alternative fuel sources, such as natural gas, nuclear, hydroelectric power and other renewable energy sources. In addition, during the last several years, the U.S. coal industry has experienced increased consolidation, which has contributed to the industry becoming more competitive. Increased competition by coal producers or producers of alternate fuels could decrease the demand for coal, our pricing of coal or length of term of coal sales contracts, adversely impacting demand for the coal that our lessees produce and thereby reducing our coal royalties revenues. Indirect competition from gas-fired plants that are less expensive to construct and easier to permit has the most potential to displace a significant amount of coal-fired generation in the near term, particularly for older, less efficient coal-powered generators.

The demand for U.S. coal exports is dependent upon a number of factors, including the overall demand for electricity in foreign markets, currency exchange rates, ocean freight rates, the demand for foreign-produced steel both in foreign markets and in the U.S. market (which is dependent in part on tariff rates on steel), general economic conditions in foreign countries, technological developments and environmental and other governmental regulations and any other pressures placed on companies that are connected to the emission of greenhouse gases. Historically, global demand for electricity and steel production has decreased during periods of economic downturn. If there is a worsening of foreign and U.S. economic and financial market conditions, and additional tightening of global credit markets, foreign demand for U.S. coal could decline, causing competition among coal producers in the United States to intensify, potentially resulting in additional downward pressure on domestic coal prices and thereby reducing our coal royalties revenues.

In addition, Federal, state and local laws and regulations extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides, mercury and other compounds emitted into the air from electric power plants, which are the ultimate consumers of the coal our lessees produce. These laws and regulations can require significant emission control expenditures for many coal-fired power plants, and various new and proposed laws and regulations may require further emission reductions and associated emission control expenditures. As a result of these current and proposed laws, regulations and trends, electricity generators may elect to switch to other fuels that generate less of these emissions, possibly further reducing demand for the coal that our lessees produce and thereby reducing our coal royalties revenues.

A substantial or extended decline in coal prices could reduce our coal royalties revenues and the value of our coal reserves.

During 2013, weaker international and domestic economies, low natural gas prices and mild weather have impacted coal markets and market weakness is expected to continue into 2014. A substantial or extended decline in coal prices could have a material adverse effect on our lessees' operations (including mine closures) and on the quantities of coal that may be economically produced from our properties. In addition, because a majority of our coal royalties are derived from coal mined on our properties under leases containing royalty rates based on the higher of a fixed base price or a percentage of the gross sales price, our coal royalties revenues could be reduced by such a decline. Such a decline could also reduce our coal services revenues and the value of our coal reserves. Additionally, volatility in coal prices could make it difficult to estimate with precision the value of our coal reserves. The future state of the global economy, including financial and credit markets on coal production levels and prices is uncertain. Depending on the longevity and ultimate severity of this downturn, demand for coal may continue to decline, which could adversely affect production and pricing for coal mined by our lessees, and, consequently, adversely affect the royalty income received by us.

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We depend on a limited number of primary operators for a significant portion of our coal royalties revenues and the loss of or reduction in production from any of our major lessees would reduce our coal royalties revenues.

We depend on a limited number of primary operators for a significant portion of our coal royalties revenues. If any of these operators enters bankruptcy or decides to cease operations or significantly reduces its production, our coal royalties revenues would be reduced.

A failure on the part of our lessees to make coal royalty payments could give us the right to terminate the lease, repossess the property or obtain liquidation damages and/or enforce payment obligations under the lease. If we repossessed any of our properties, we would seek to find a replacement lessee. We may not be able to find a replacement lessee and, if we find a replacement lessee, we may not be able to enter into a new lease on favorable terms within a reasonable period of time. In addition, the outgoing lessee could be subject to bankruptcy proceedings that could further delay the execution of a new lease or the assignment of the existing lease to another operator. If we enter into a new lease, the replacement operator might not achieve the same levels of production or sell coal at the same price as the lessee it replaced.

Our coal reserves decline as our lessees mine our coal and our inability to acquire additional coal reserves that are economically recoverable may have a material adverse effect on the future profitability of our coal business.

Because our reserves decline as our lessees mine our coal, we have historically expanded our coal operations by adding and developing coal reserves in existing, adjacent and neighboring properties and through acquisitions of additional coal reserves that are economically recoverable to replace the reserves we produce. If we are unable to negotiate purchase contracts to replace or increase our coal reserves on acceptable terms, our coal royalties revenues will decline as our coal reserves are eventually depleted. As of December 31, 2013, PVR owned or controlled approximately 847 million tons of proven or probable coal reserves located in Kentucky, Virginia, West Virginia, Illinois and New Mexico. PVR anticipates that these reserves will take over 34 years to deplete, based upon 2013 production volumes. Our current business strategy does not contemplate any additional growth in our coal reserve holdings through acquisitions or investments in our existing market areas. During 2014, our coal reserves located in the San Juan Basin will deplete and the associated royalty revenue will cease.

Our lessees could satisfy obligations to their customers with coal from properties other than ours, depriving us of the ability to receive amounts in excess of the minimum coal royalties payments.

We do not control our lessees' business operations. Our lessees' customer supply contracts do not generally require our lessees to satisfy their obligations to their customers with coal mined from our reserves. Several factors may influence a lessee's decision to supply its customers with coal mined from properties we do not own or lease, including the royalty rates under the lessee's lease with us, mining conditions, transportation costs and availability and customer coal quality specifications. If a lessee satisfies its obligations to its customers with coal from properties we do not own or lease, production under our lease will decrease, and we will receive lower coal royalties revenues.

Fluctuations in transportation costs and the availability or reliability of transportation could reduce the production of coal mined from our properties.

Transportation costs represent a significant portion of the total cost of coal for the customers of our lessees. Increases in transportation costs could make coal a less competitive source of energy or could make coal produced by some or all of our lessees less competitive than coal produced from other sources. On the other hand, significant decreases in transportation costs could result in increased competition for our lessees from coal producers in other parts of the country or increased imports from offshore producers.

Our lessees depend upon rail, barge, trucking, overland conveyor and other systems to deliver coal to their customers. Disruption of these transportation services due to weather-related problems, strikes, lockouts, bottlenecks, mechanical failures and other events could temporarily impair the ability of our lessees to supply coal to their customers. Our lessees' transportation providers may face difficulties in the future and impair the ability of our lessees to supply coal to their customers, thereby resulting in decreased coal royalties revenues to us.

Our lessees' workforces could become increasingly unionized in the future, which could adversely affect their productivity and thereby reduce our coal royalties revenues.

One of our lessees has one mine operated by unionized employees. This mine was our third largest mine on the basis of coal production for the three-months ended March 31, 2014. All of our lessees could become increasingly unionized in the future. If some or all of our lessees' non-unionized operations were to become unionized, it could adversely affect their productivity due to a potential increase in the risk of work stoppages. In addition, our lessees' operations may be adversely affected by work stoppages at unionized companies, particularly if union workers were to orchestrate boycotts against our lessees' operations. Any further unionization of our lessees' employees could adversely affect the stability of production from our coal reserves and reduce our coal royalties revenues.

Our coal reserve estimates depend on many assumptions that may be inaccurate, which could materially adversely affect the quantities and value of our coal reserves.

Our estimates of our coal reserves may vary substantially from the actual amounts of coal our lessees may be able to economically recover. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. Estimates of coal reserves necessarily depend upon a number of variables and assumptions, any one of which may, if incorrect, result in an estimate that varies considerably from actual results. These factors and assumptions relate to:

- geological and mining conditions, which may not be fully identified by available exploration data;
- the amount of ultimately recoverable coal in the ground;
- the effects of regulation by governmental agencies; and
- future coal prices, operating costs, capital expenditures, severance and excise taxes and development and reclamation costs.

Actual production, revenues and expenditures with respect to our coal reserves will likely vary from estimates, and these variations may be material. As a result, you should not place undue reliance on the coal reserve data provided by us.

We may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations or releases of hazardous materials into the environment.

Our operations are subject to stringent and complex federal, state and local environmental laws and regulations governing, among other things, air emissions, wastewater discharges, the use, management and disposal of hazardous and nonhazardous materials and wastes, and the cleanup of contamination. Noncompliance with such laws and regulations, or incidents resulting in environmental releases, could cause us to incur substantial costs, penalties, fines and other criminal sanctions, third party claims for personal injury or property damage, investments to retrofit or upgrade our facilities and programs, or curtailment of operations. Certain environmental statutes, including CERCLA and comparable state laws, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed or otherwise released.

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to the necessity of handling natural gas and NGLs, air emissions related to our operations, and historical industry operations and waste disposal practices. For example, an accidental release from one of our pipelines or processing facilities could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover these costs from insurance. We cannot be certain that identification of presently unidentified conditions, more vigorous enforcement by regulatory agencies, enactment of more stringent laws and regulations, or other unanticipated events will not arise in the future and give rise to material environmental liabilities that could have a material adverse effect on our business, financial condition or results of operations.

Federal and state laws restricting the emissions of greenhouse gases in many jurisdictions could adversely affect our coal royalties revenues.

Global climate change continues to attract considerable public and scientific attention. Several scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases", or GHGs, including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. Legislative attention in the United States is being paid to reducing GHG emissions. Many states have already taken legal measures to reduce emissions of GHGs, primarily through the development of regional GHG cap-and-trade programs.

There are many regulatory approaches currently in effect or being considered to address GHGs, including possible future U.S. treaty commitments, new federal or state legislation that may impose a carbon emissions tax or establish a cap-and-trade program and regulation by the EPA. EPA rules require extensive regulation of GHG emissions from mobile sources and stationary sources, including imposing permitting requirements and obligations to use best available control technology for the reduction of GHG

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emissions whenever certain stationary sources, such as power plants, are built or significantly modified. Moreover, the EPA has updated pollution standards for fossil fuel power plants and petroleum refineries.

On April 13, 2013, the EPA published draft rules regulating for carbon dioxide emissions from new and modified EGUs. The final NSPS, if promulgated along the lines proposed, would pose significant challenges for the construction of new coal-fired power plants and could result in a decrease in U.S. demand for steam coal. In its Climate Action Plan, the Obama Administration announced its intent to issue regulations under Section 111(b) and Section 111(d) of the CAA to set standards for both new and existing power plants by June 2015.

The permitting of new coal-fired power plants has also been contested by state regulators and environmental organizations for concerns related to greenhouse gas emissions from the new plants. Other state regulatory authorities have also rejected the construction of new coal-fired power plants based on the uncertainty surrounding the potential costs associated with greenhouse gas emissions from these plants under future laws limiting the emissions of carbon dioxide. In addition, several permits issued to new coal-fired power plants without limits on greenhouse gas emissions have been appealed to EPA's Environmental Appeals Board. The regulation of emissions of GHGs associated with the use of coal may lead our lessees' customers to curtail their operations, switch to other fuels or other alternatives which may, individually and collectively, reduce demand for our lessees' coal and thereby decrease revenues. As a result of current laws and proposed laws, regulations and trends, electric generators may switch from coal to other fuels that generate less greenhouse gas emissions, possibly reducing demand for coal.

Delays in obtaining, inability to obtain, or revocation of our lessees' mining permits and approvals could have an adverse effect on our coal royalties revenues.

Mine operators, including our lessees, must obtain numerous permits and approvals that impose strict conditions and obligations relating to various environmental and safety matters in connection with coal mining. The permitting rules, and the interpretations of these rules, are complex, change frequently, and are often subject to discretionary interpretations by regulators, all of which may make compliance more difficult, and may possibly preclude the continuance of ongoing mining operations or the development of future mining operations.

To dispose of mining overburden generated from surface mining activities, our lessees often need to obtain government approvals, including CWA Section 404 permits to construct valley fills, stream impoundments, and sediment control ponds. Recently, these Section 404 permits and the Section 404 permitting standard have been the target of increased scrutiny by environmental groups, legislators, the White House, and the EPA which has made it more difficult for miners to obtain, and in some cases maintain, Section 404 permits. In one case, the EPA retroactively rescinded a permit that had been issued. The U.S. Office of Surface Mining and Reclamation is in the process of rewriting the "stream buffer zone rule" which currently requires surface mining operators to minimize soil disturbances and dispose of excess mining spoil away from water sources. If the EPA promulgates a more restrictive stream buffer zone rule, any such additional requirements could impact coal mining operations, particularly in Appalachia, including, for example, by reducing locations where coal mining operations can be conducted or by further restricting common spoil disposal practices. Regulations which dramatically increase the costs of compliance or prohibit our lessees from obtaining new permits could reduce coal production and cash flows, and could ultimately have an adverse effect on our royalty revenues.

Our lessees' mining operations are subject to extensive and costly laws and regulations, which could increase operating costs and limit our lessees' ability to produce coal, which could have an adverse effect on our coal royalties revenues.

Our lessees are subject to federal, state and local laws and regulations affecting coal mining operations, including laws and regulations pertaining to employee health and safety, permitting and licensing requirements, air quality standards, water pollution, plant and wildlife protection, reclamation and restoration of mining properties after mining is completed, the discharge of materials into the environment, surface subsidence from underground mining and the effects that mining has on groundwater quality and availability. Our lessees are required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed exploration for or production of coal may have upon the environment. The costs, liabilities and requirements associated with these regulations may be significant and time-consuming and may delay commencement or continuation of exploration or production operations. The possibility exists that new laws or regulations (or judicial interpretations of existing laws and regulations) may be adopted in the future that could materially affect our lessees' mining operations, either through direct impacts such as new requirements impacting our lessees' existing mining operations, or indirect impacts such as new laws and regulations that discourage or limit coal consumers' use of coal. Any of these direct or indirect impacts could have an adverse effect on our coal royalties revenues.

Because of extensive and comprehensive regulatory requirements, violations during mining operations are not unusual in the industry and, notwithstanding compliance efforts, we do not believe violations by our lessees can be eliminated completely. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition

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of cleanup and site restoration costs and liens and, to a lesser extent, the issuance of injunctions to limit or cease operations. Our lessees may also incur costs and liabilities resulting from claims for damages to property or injury to persons arising from their operations. If our lessees are required to pay these costs and liabilities and if their financial viability is affected by doing so, then their mining operations and, as a result, our coal royalties revenues and our ability to make distributions, could be adversely affected.

Our lessees operations may impact the environment or cause exposure to hazardous substances, and our properties may have environmental contamination, which could result in material liabilities to us.

Our lessees operations currently use hazardous materials and generate limited quantities of hazardous wastes from time to time. We could become subject to claims for toxic torts, natural resource damages and other damages as well as for the investigation and clean up of soil, surface water, groundwater, and other media. Such claims may arise, for example, out of conditions at sites that we currently own as well as at sites that we previously owned, or may acquire. We may be held responsible for more than our share of the contamination or other damages, or even for the entire share.

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

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

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

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

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
4.1	Second Supplemental Indenture dated as of February 10, 2014 among Regency Energy Partners LP, a Delaware limited partnership, Regency Energy Finance Corp., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee.	8-K	February 10, 2014 001-35262
4.2	Third Supplemental Indenture dated as of February 10, 2014 among Regency Energy Partners LP, Regency Energy Finance Corp., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (including the form of the notes).	8-K	February 10, 2014 001-35262
4.3	Second Supplemental Indenture dated February 10, 2014 among Regency Energy Partners LP, Regency Energy Finance Corp., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee.	8-K	February 10, 2014 001-35262
4.4	Seventh Supplemental Indenture dated as of February 10, 2014 among Regency Energy Partners LP, Regency Energy Finance Corp., the guarantors party thereto, and U.S. Bank National Association, as trustee.	8-K	February 10, 2014 001-35262
4.5	Indenture, dated as of April 27, 2010, by and among PVR Partners, L.P., Penn Virginia Resource Finance Corporation, the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to PVR Partners, L.P.'s Current Report on Form 8-K filed on April 27, 2010.	8-K	March 24, 2014 001-16735
4.6	Second Supplemental Indenture, dated as of May 17, 2012, by and among PVR Partners, L.P., Penn Virginia Resource Finance Corporation II, the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to PVR Partners, L.P.'s Current Report on Form 8-K filed on May 23, 2012.	8-K	March 24, 2014 001-16735
4.7	Fourth Supplemental Indenture, dated as of May 9, 2013, by and among PVR Partners, L.P., Penn Virginia Resource Finance Corporation II, the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to PVR Partners, L.P.'s Current Report on Form 8-K filed on May 10, 2013.	8-K	March 24, 2014 001-16735
4.8	Fifth Supplemental Indenture, dated as of March 21, 2014, by and among Regency Energy Partners LP, Regency Energy Finance Corp., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee.	8-K	March 24, 2014 001-16735

4.9	Registration Rights Agreement dated as of February 3, 2014, by and between Hoover Energy Partners LP and Regency Energy Partners LP.	8-K	February 5, 2014 001-35262
4.10	Third Supplemental Indenture dated March 28, 2014 among RHEP Crude LLC, Regency Energy Partners LP, Regency Finance Corp., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee.	**	
4.11	Fourth Supplemental Indenture dated April 18, 2014 among PVR Midstream JV Holdings LLC, Regency Hydrocarbons LLC, Regency Laverne LLC, Connect Gas Pipeline LLC, Regency Pipeline LLC, Regency Utica Gas Gathering LLC, Regency Marcellus Gas Gathering LLC, Regency NEPA Gas Gathering LLC, Penn Virginia Operating Co., LLC, Dulcet Acquisition LLC, Fieldcrest Resources LLC, K Rail LLC, Kanawha Rail LLC, LJL, LLC, Loadout LLC, Suncrest Resources LLC, Toney Fork LLC, Regency Energy Partners LP, Regency Energy Finance Corp., guarantors party thereto, and Wells Fargo Bank, National Association, as trustee.	**	
4.12	Fourth Supplemental Indenture dated March 28, 2014 among RHEP Crude LLC, Regency Energy Partners LP, Regency Finance Corp., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee.	**	

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Exhibit Number	Description	Incorporated by Reference from Form	Date Filed and File No
4.13	Fifth Supplemental Indenture dated April 18, 2014 among PVR Midstream JV Holdings LLC, Regency Hydrocarbons LLC, Regency Laverne LLC, Connect Gas Pipeline LLC, Regency Pipeline LLC, Regency Utica Gas Gathering LLC, Regency Marcellus Gas Gathering LLC, Regency NEPA Gas Gathering LLC, Penn Virginia Operating Co., LLC, Dulcet Acquisition LLC, Fieldcrest Resources LLC, K Rail LLC, Kanawha Rail LLC, LJL, LLC, Loadout LLC, Suncrest Resources LLC, Toney Fork LLC, Regency Energy Partners LP, Regency Energy Finance Corp., guarantors party thereto, and Wells Fargo Bank, National Association, as trustee.	**	
4.14	Sixth Supplemental Indenture dated April 18, 2014 among Regency Energy Partners LP, Regency Finance Corp., Subsidiary Guarantors and Wells Fargo Bank, National Association, as trustee.	**	
4.15	Eighth Supplemental Indenture dated March 28, 2014 among RHEP Crude LLC, Regency Energy Partners LP, Regency Finance Corp., the guarantors party thereto and U.S. Bank National Association, as trustee.	**	
4.16	Ninth Supplemental Indenture dated April 18, 2014 among PVR Midstream JV Holdings LLC, Regency Hydrocarbons LLC, Regency Laverne LLC, Connect Gas Pipeline LLC, Regency Pipeline LLC, Regency Utica Gas Gathering LLC, Regency Marcellus Gas Gathering LLC, Regency NEPA Gas Gathering LLC, Penn Virginia Operating Co., LLC, Dulcet Acquisition LLC, Fieldcrest Resources LLC, K Rail LLC, Kanawha Rail LLC, LJL, LLC, Loadout LLC, Suncrest Resources LLC, Toney Fork LLC, Regency Energy Partners LP, Regency Energy Finance Corp., guarantors party thereto, and U.S. Bank National Association, as trustee.	**	
10.1	Membership Interest Purchase and Sale Agreement dated April 9, 2012 among Chief E&D Holdings LP, Chief Gathering LLC, PVR Marcellus Gas Gathering LLC, and Penn Virginia Resource Partners, L.P..	*	
10.2	Non-Competition Agreement, dated as of February 3, 2014, by and among Regency Energy Partners LP, Regency HEP LLC and Hoover Energy Partners LP.	8-K	February 5, 2014 001-35262
10.3	Escrow Agreement, dated as of February 3, 2014, by and among Regency Energy Partners LP, Regency HEP LLC, Hoover Energy Partners LP and Wells Fargo Bank, National Association, as	8-K	February 5, 2014 001-35262

	escrow agent.		
10.4	First Amendment to Sixth Amended and Restated Credit Agreement, dated February 18, 2014.	8-K	February 21, 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.		

* Incorporated by reference from Exhibit 2.1 to PVR Partners, L.P.'s Current Report on Form 8-K filed on April 12, 2012.
** 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: May 8, 2014

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