Regency Energy Partners LP
Form 10-Q
May 08, 2015

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, 2015
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	16-1731691
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
3738 OAK LAWN AVENUE DALLAS, TX	75219
(Address of principal executive offices)	(Zip Code)

(214) 981-0700
(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

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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
Bbls	Barrels
bps	Basis points
Eagle Rock	Eagle Rock Energy Partners, L.P.
ELG	Edwards Lime Gathering LLC and its wholly-owned subsidiaries, ELG Oil LLC and ELG Utility LLC
ETC	Energy Transfer Company, the name assumed by La Grange Acquisition, L.P. for conducting business and shared services, a wholly-owned subsidiary of ETP
ETE	Energy Transfer Equity, L.P.
ETP	Energy Transfer Partners, L.P.
ETP GP	Energy Transfer Partners GP, L.P.
Exchange Act	Securities Exchange Act of 1934, as amended
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 its board of directors and Regency Employees Management LLC
Grey Ranch	Grey Ranch Plant LP, a former joint venture of the Partnership
Gulf States	Gulf States Transmission LLC, a wholly-owned subsidiary of the Partnership
Hoover	Hoover Energy Partners, LP
HPC	RIGS Haynesville Partnership Co. 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
Mi Vida JV	Mi Vida JV 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
ORS	Ohio River System LLC
Partnership	Regency Energy Partners LP
PVR	PVR Partners, L.P.
Ranch JV	Ranch Westex JV LLC
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 2019 Notes, 2020 Notes, 2020 PVR Notes, 2021 Notes, 2021 PVR Notes, 2022 Notes, October 2022 Notes, 2023 4.5% Notes and 2023 5.5% Notes

Series A Preferred Units	Series A convertible redeemable preferred units

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Name	Definition or Description
Services Co.	ETE Services Company, LLC
Sweeny JV	Sweeny Gathering, L.P.
U.S.	United States
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;
- ETP’s ability to successfully integrate our operations and employees and to realize synergies and cost savings;
- unexpected difficulties in integrating any significant acquisitions into our operations;
- 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 financing on satisfactory terms;
- our use of derivative financial instruments to hedge commodity risks;
- the amount of collateral required to be posted from time-to-time in our transactions;
- changes in commodity prices, interest rates and demand for our services;
- changes in laws and regulations or enforcement practices impacting the midstream sector of the natural gas industry, oil industry and the coal mining industry, including those that relate to climate change and environmental protection and safety, including with respect to emissions levels applicable to coal-burning power generators and permissible levels of mining runoff;
- the adoption of new laws, or the promulgation of new regulations, at the federal, state or local level that promote use and development of renewable energy or limit use or development of fossil fuels;
- weather and other natural phenomena;
- industry changes including the impact of consolidation and changes in competition;
- regulation of transportation rates on our natural gas, NGL, and oil pipelines;
- our ability to obtain indemnification related to cleanup liabilities and to clean up any hazardous materials release on satisfactory terms;
- our ability to obtain required approvals for construction or modernization of our facilities and the timing of production from such facilities;
- the effect of accounting pronouncements issued periodically by accounting standard setting boards;
- the extent to which the amount and quality of actual production of our coal differs from estimated recoverable coal reserves;
- the experience and financial condition of our coal lessees, including our lessees’ ability to satisfy their royalty, environmental, reclamation and other obligations to us and others;
- operating risks, including unanticipated geological problems, incidental to our Gathering and Processing segment and Natural Resources segment;
- the ability of our lessees to produce sufficient quantities of coal on an economic basis from our reserves and obtain favorable contracts for such production;
- delays in anticipated start-up dates of new development in our Gathering and Processing segment and our lessees’ mining operations and related coal infrastructure projects, including the timing of receipt of necessary governmental permits by us or our lessees; and
- uncertainties relating to the effects of regulatory guidance on permitting under the Clean Water Act and the outcome of current and future litigation regarding mine permitting.

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If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may differ materially from those anticipated, estimated, projected or expected.

Other factors that could cause our actual results to differ from our projected results are discussed in Item 1A of our December 31, 2014 Annual Report on Form 10-K.

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
(Dollars in millions)
(unaudited)

	March 31, 2015	December 31, 2014
ASSETS		
Current Assets:		
Cash and cash equivalents	$59	$24
Trade accounts receivable, net of allowance for doubtful accounts of $9 and $7	384	483
Related party receivables	76	45
Inventories	63	67
Derivative assets	65	75
Other current assets	16	9
Total current assets	663	703
Property, plant and equipment	10,706	10,260
Less accumulated depreciation and depletion	(1,166)	(1,043)
Property, plant and equipment, net	9,540	9,217
Investments in unconsolidated affiliates	2,484	2,418
Other, net of accumulated amortization of debt issuance costs of $30 and $28	101	103
Intangible assets, net of accumulated amortization of $244 and $212	3,405	3,439
Goodwill	1,223	1,223
TOTAL ASSETS	$17,416	$17,103
LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Drafts payable	$23	$15
Trade accounts payable	407	529
Related party payables	25	64
Accrued expenses	53	43
Accrued interest	105	81
Other current liabilities	30	24
Total current liabilities	643	756
Long-term derivative liabilities	14	16
Other long-term liabilities	74	72
Long-term debt, net	7,221	6,641
Commitments and contingencies		
Series A Preferred Units, redemption amounts of $38 and $38	33	33
Partners' capital and noncontrolling interest:		
Common units	8,351	8,531
Class F units	155	153
General partner interest	770	781
Total partners' capital	9,276	9,465
Noncontrolling interest	155	120
Total partners' capital and noncontrolling interest	9,431	9,585
	$17,416	$17,103

TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST

The accompanying notes are an integral part of these condensed consolidated financial statements.
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REGENCY ENERGY PARTNERS LP
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in millions, except unit data and per unit data)
(unaudited)

	Three Months Ended March 31, 2015	2014
REVENUES		
Gas sales, including related party amounts of $8 and $13	$374	$335
NGL sales, including related party amounts of $123 and $50	254	331
Gathering, transportation and other fees, including related party amounts of $5 and $6	315	172
Net realized and unrealized gain (loss) from derivatives	11	(13)
Other	45	38
Total revenues	999	863
OPERATING COSTS AND EXPENSES		
Cost of sales, including related party amounts of $19 and $10	641	638
Operation and maintenance	133	78
General and administrative	36	33
Gain on asset sales, net	—	(2)
Depreciation, depletion and amortization	158	94
Total operating costs and expenses	968	841
OPERATING INCOME	31	22
Income from unconsolidated affiliates	50	43
Interest expense, net	(82)	(56)
Other income and deductions, net	3	2
INCOME BEFORE INCOME TAXES	2	11
Income tax expense (benefit)	5	(1)
NET (LOSS) INCOME	$(3)	$12
Net income attributable to noncontrolling interest	(4)	(3)
NET (LOSS) INCOME ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$(7)	$9
Amounts attributable to Series A Preferred Units	1	1
General partner's interest, including IDRs	—	5
Beneficial conversion feature for Class F units	2	2
Limited partners' interest in net (loss) income	$(10)	$1
Basic and diluted net (loss) income per common unit:		
Amount allocated to common units	$(10)	$1
Weighted average number of common units outstanding	410,670,934	226,046,232
Basic (loss) income per common unit	$(0.02)	$0.00
Diluted (loss) income per common unit	$(0.02)	$0.00
Distributions per common unit	$—	$0.48
Amount allocated to Class F units due to beneficial conversion feature	$2	$2
Total number of Class F units outstanding	6,274,483	6,274,483
Income per Class F unit due to beneficial conversion feature	$0.27	$0.27

The accompanying notes are an integral part of these condensed consolidated financial statements.
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REGENCY ENERGY PARTNERS LP
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME
(Dollars in millions)
(unaudited)

	Three Months Ended March 31,	
	2015	2014
Net (loss) income	$(3)	$12
Other comprehensive income	—	—
Total other comprehensive income	—	—
Comprehensive (loss) income	(3)	12
Comprehensive income attributable to noncontrolling interest	4	3
Comprehensive (loss) income attributable to Regency Energy Partners LP	$(7)	$9

The accompanying notes are an integral part of these condensed consolidated financial statements.

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REGENCY ENERGY PARTNERS LP
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in millions)
(unaudited)

	Three Months Ended March 31,	
	2015	2014
OPERATING ACTIVITIES:		
Net (loss) income	$(3)	$12
Reconciliation of net (loss) income to net cash flows provided by operating activities:		
Depreciation, depletion and amortization, including debt issuance cost amortization and bond premium write-off and amortization	158	97
Income from unconsolidated affiliates	(50)	(43)
Derivative valuation changes	9	17
Gain on asset sales, net	—	(2)
Unit-based compensation expenses	4	2
Cash flow changes in current assets and liabilities:		
Trade accounts receivable and related party receivables	64	(21)
Other current assets and other current liabilities	35	35
Trade accounts payable and related party payables	(149)	48
Distributions of earnings received from unconsolidated affiliates	52	43
Cash flow changes in other assets and liabilities	2	(1)
Net cash flows provided by operating activities	122	187
INVESTING ACTIVITIES:		
Capital expenditures	(457)	(215)
Capital contributions to unconsolidated affiliates	(90)	(40)
Distributions in excess of earnings of unconsolidated affiliates	21	9
Acquisitions, net of cash received	—	(213)
Proceeds from asset sales	3	5
Net cash flows used in investing activities	(523)	(454)
FINANCING ACTIVITIES:		
Borrowings (repayments) under revolving credit facility, net	583	(519)
Proceeds from issuances of senior notes	—	886
Debt issuance costs	(1)	(16)
Drafts payable	8	(8)
Partner distributions and distributions on unvested unit awards	(218)	(107)
Common units issued under unit offerings, equity distribution program and LTIP, net of issuance costs, forfeitures and tax withholding	34	34
Distributions to Series A Preferred Units	(1)	(1)
Noncontrolling interest contributions (distributions), net	31	(8)
Net cash flows provided by financing activities	436	261
Net change in cash and cash equivalents	35	(6)
Cash and cash equivalents at beginning of period	24	19
Cash and cash equivalents at end of period	$59	$13
Supplemental cash flow information:		
Accrued capital expenditures	$80	$24
Interest paid, net of amounts capitalized	64	29
Issuance of common units in connection with PVR and Hoover acquisitions	—	4,015

Long-term debt assumed in PVR Acquisition	—	1,887

The accompanying notes are an integral part of these condensed consolidated financial statements.
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REGENCY ENERGY PARTNERS LP
CONDENSED CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
AND NONCONTROLLING INTEREST
(Dollars in millions)
(unaudited)

	Regency Energy Partners LP				
	Common Units	Class F Units	General Partner Interest	Noncontrolling Interest	Total
Balance - December 31, 2014	$8,531	$153	$781	$120	$9,585
Issuance of common units under equity distribution program, net of costs	34	—	—	—	34
Unit-based compensation expenses	3	—	—	—	3
Partner distributions and distributions on unvested unit awards	(207)	—	(11)	—	(218)
Noncontrolling interest contributions, net of distributions	—	—	—	31	31
Net (loss) income	(9)	2	—	4	(3)
Distributions to Series A Preferred Units	(1)	—	—	—	(1)
Balance - March 31, 2015	$8,351	$155	$770	$155	$9,431

The accompanying notes are an integral part of these 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; natural gas and NGL marketing and trading, 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.

Merger with ETP. On April 30, 2015, the Partnership merged with a wholly-owned subsidiary of ETP, with the Partnership continuing as the surviving entity and becoming a wholly-owned subsidiary of ETP (the “Merger”). At the effective time of the Merger (the “Effective Time”), each Partnership common unit and Class F unit converted into the right to receive 0.4124 ETP common units. Based on the Partnership units outstanding, ETP issued approximately 172.2 million ETP Common Units to the Partnership’s unitholders, including approximately 15.5 million units issued to ETP subsidiaries. Series A Preferred Units converted into the right to receive a preferred unit representing a limited partner interest in ETP, a new class of units in ETP established at the Effective Time. The merger was a combination of entities under common control; therefore, the carrying amounts of the Partnership's assets and liabilities will not be adjusted.

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, 2014. 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 intercompany 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.

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.” In connection with the Merger in April 2015, each Class F unit converted into the right to receive 0.4124 ETP common units.

Equity Distribution Agreement. During the three months ended March 31, 2015, the Partnership received net proceeds of $34 million from common units sold pursuant to an equity distribution agreement which were used for general partnership purposes. The Partnership did not issue any common units under the equity distribution agreement subsequent to March 31, 2015, and the equity distribution agreement terminated as a result of the ETP Merger in April 2015.

Units Activity. The change in common and Class F units during the three months ended March 31, 2015 was as follows:

	Common	Class F
Balance - December 31, 2014	409,406,482	6,274,483
Issuance of common units under LTIP, net of forfeitures and tax withholding	20,098	—
Issuance of common units under the equity distribution agreement	1,516,677	—
Balance - March 31, 2015	410,943,257	6,274,483

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3. (LOSS) INCOME PER COMMON UNIT

The following tables provide a reconciliation of the numerator and denominator of the basic and diluted (loss) earnings per common unit computations for the three months ended March 31, 2015 and 2014:

	Three Months Ended March 31,					
	2015			2014		
	Loss (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
Basic (loss) income per unit						
Amount allocated to common units	$(10)	410,670,934	$(0.02)	$1	226,046,232	$0.00
Effect of Dilutive Securities:						
Common unit options	—	—		—	22,787	
Phantom units	—	—		—	424,332	
Series A Preferred Units	—	—		—	2,054,217	
Diluted (loss) income per unit	$(10)	410,670,934	$(0.02)	$1	228,547,568	$0.00

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, 2015
Common unit options	1,425
Phantom units	675,700
Series A preferred units	2,068,508

4. INVESTMENTS IN UNCONSOLIDATED AFFILIATES

The carrying value of the Partnership's investment in each of the unconsolidated affiliates as of March 31, 2015 and December 31, 2014 is as follows:

	Ownership	Type	March 31, 2015	December 31, 2014
HPC	49.99%	General Partner	$417	$422
MEP	50.00%	Membership Interest	687	695
Lone Star	30.00%	Membership Interest	1,217	1,162
Ranch JV	33.33%	Membership Interest	36	38
Aqua - PVR	51.00%	Membership Interest	45	46
Mi Vida JV	50.00%	Membership Interest	81	54
Others [(1)]			1	1
Total			$2,484	$2,418

(1) Others includes Coal Handling, Sweeny JV and Grey Ranch

The following tables summarize the Partnership's investment activities in each of the unconsolidated affiliates for the three months ended March 31, 2015 and 2014:

	Three Months Ended March 31, 2015					
	HPC	MEP	Lone Star	Ranch JV	Aqua - PVR	Mi Vida JV
Contributions to unconsolidated affiliates	$—	$—	$63	$—	$—	$27
Distributions from unconsolidated affiliates	(13)	(20)	(37)	(3)	—	—
Share of earnings of unconsolidated affiliates' net income (loss)	9	12	29	2	(1)	—
Amortization of excess fair value of investment	(1)	—	—	—	—	—

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	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)	—	—	—	—

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, 2015 and 2014:

	Three Months Ended March 31, 2015				
	HPC	MEP	Lone Star	Ranch JV	Aqua - PVR
Total revenues	$38	$62	$803	$8	$—
Operating income (loss)	22	31	97	5	(2)
Net income (loss)	19	23	97	5	(2)

	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

5. DERIVATIVE INSTRUMENTS

Policies. The Partnership established comprehensive risk management policies and procedures to monitor and manage the market risks associated with commodity prices, counterparty credit and interest rates. The General Partner is responsible for delegation of transaction authority levels, and the Audit and Risk Committee of the General Partner is responsible for 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.

The Partnership has swap contracts settled against certain NGLs, condensate and natural gas market prices. In April 2015, the Partnership terminated all outstanding swap contracts and received net proceeds of $56 million.

Marketing & Trading. The Partnership conducts natural gas marketing and trading activities intended to capitalize on favorable price differentials between various receipt and delivery locations. The Partnership enters into both financial derivatives and physical contracts. These financial derivatives, primarily basis swaps, are transacted: (i) to economically hedge subscribed capacity exposed to market rate fluctuations and (ii) to mitigate the price risk related to other purchases and sales of natural gas. By entering into a basis swap, one pricing index is exchanged for another, effectively locking in the margin between the natural gas purchase and sale by removing index spread risk on the combined physical and financial transaction. Changes in the fair value of these financial and physical contracts are recorded as adjustments to natural gas sales and realized (unrealized) gain (loss) from derivatives, as appropriate.

The Partnership has credit exposure to additional counterparties. The Partnership monitors its exposure to any single counterparty and the creditworthiness of its counterparties on an ongoing basis. In addition, the Partnership's natural gas purchase and sale

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contracts, for certain counterparties, are subject to counterparty netting agreements governing settlement under such natural gas purchase and sales contracts, and when possible, the Partnership nets the open positions of each counterparty.

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, 2015, the Partnership had $2.1 billion of outstanding borrowings exposed to variable interest rate risk.

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

The Partnership is exposed to credit risk from its derivative contract counterparties. The Partnership does not require collateral from these counterparties. The Partnership deals primarily with financial institutions when entering into financial derivatives, and utilizes master netting agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximum loss as of March 31, 2015 would be $72 million, which would be reduced by $1 million, due to the netting features. The Partnership has elected to present assets and liabilities under master netting agreements gross on the condensed consolidated balance sheets.

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

The Partnership's derivative assets and liabilities, including credit risk adjustments, as of March 31, 2015 and December 31, 2014 are detailed below:

	Assets		Liabilities	
	March 31, 2015	December 31, 2014	March 31, 2015	December 31, 2014
Derivatives not designated as cash flow hedges				
Current amounts				
Commodity contracts	$65	$75	$1	$—
Long-term amounts				
Commodity contracts	9	10	—	—
Embedded derivatives in Series A Preferred Units	—	—	14	16
Total derivatives	$74	$85	$15	$16

The Partnership's statements of operations for the three months ended March 31, 2015 and 2014 were impacted by derivative instruments activities as follows:

		Three Months Ended March 31,	
		2015	2014
Derivatives not designated in a hedging relationship	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Recognized in Income on Derivatives	
Commodity derivatives	Revenues	$11	$(13)
Embedded derivatives in Series A Preferred Units	Other income & deductions, net	2	(1)
		$13	$(14)

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6. LONG-TERM DEBT

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

	March 31, 2015	December 31, 2014
Senior notes	$5,089	$5,089
Revolving loans	2,087	1,504
Unamortized premium and discounts	45	48
Long-term debt	$7,221	$6,641
Availability under revolving credit facility:		
Total credit facility limit	$2,500	$2,000
Revolving loans	(2,087)	(1,504)
Letters of credit	(16)	(23)
Total available	$397	$473

Long-term debt maturities as of March 31, 2015 for each of the next five years are as follows:

Years Ending December 31,	Amount
2015 (remainder)	$—
2016	—
2017	—
2018	—
2019	2,586
Thereafter	4,590
Total *	$7,176

* Excludes a $64 million unamortized premium on the 2020 PVR Notes and the 2021 PVR Notes assumed by the Partnership and a $19 million unamortized discount on the combined 2022 Notes.

Revolving Credit Facility

The weighted average interest rate on the amounts outstanding under the Partnership's Credit Agreement was 2.18% as of March 31, 2015.

On April 30, 2015, in connection with the Merger, the revolving credit facility was paid off in full and terminated. As a result, compliance with material covenants is no longer applicable as of the reporting date.

Senior Notes

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

7. COMMITMENTS AND CONTINGENCIES

Legal. The Partnership is involved in various claims, lawsuits and audits by taxing authorities incidental to its business. These claims and lawsuits in the aggregate are not expected to have a material adverse effect on the Partnership's business, financial condition, results of operations or cash flows.

ETP Merger Shareholder Litigation. Following the January 26, 2015 announcement of the definitive merger agreement with ETP, purported Partnership unitholders filed lawsuits in state and federal courts in Dallas, Texas asserting claims relating to the proposed transaction.

On February 3, 2015, William Engel and Enno Seago, purported Partnership unitholders, filed a class action petition on behalf of the Partnership's common unitholders and a derivative suit on behalf of the Partnership in the 162nd Judicial District Court of Dallas County, Texas (the "Engel Lawsuit"). The lawsuit names as defendants the General Partner, the members of the General Partner's board of directors, ETP, ETP GP, ETE, and, as a nominal party, the Partnership. The Engel Lawsuit alleges that (1) the General Partner's directors breached duties to the Partnership and the Partnership's unitholders by employing a conflicted and unfair process and failing to maximize the merger consideration; (2) the General Partner's directors breached the implied covenant of good faith and fair dealing by engaging in a flawed merger process; and (3) the non-director defendants aided and abetted in these claimed breaches. The plaintiffs seek an injunction preventing the defendants from closing the proposed transaction or an order rescinding the transaction if it has already been completed. The plaintiffs also seek money damages and court costs, including attorney's fees.

On February 9, 2015, Stuart Yeager, a purported Partnership unitholder, filed a class action petition on behalf of the Partnership's common unitholders and a derivative suit on behalf of the Partnership in the 134th Judicial District Court of Dallas County, Texas (the "Yeager Lawsuit"). The allegations, claims, and relief sought in the Yeager Lawsuit are nearly identical to those in the Engel Lawsuit.

On February 10, 2015, Lucien Coggia a purported Partnership unitholder, filed a class action petition on behalf of the Partnership's common unitholders and a derivative suit on behalf of the Partnership in the 192nd Judicial District Court of Dallas County, Texas (the "Coggia Lawsuit"). The allegations, claims, and relief sought in the Coggia Lawsuit are nearly identical to those in the Engel Lawsuit.

On February 3, 2015, Linda Blankman, a purported Partnership unitholder, filed a class action complaint on behalf of the Partnership's common unitholders in the United States District Court for the Northern District of Texas (the "Blankman Lawsuit"). The allegations and claims in the Blankman Lawsuit are similar to those in the Engel Lawsuit. However, the Blankman Lawsuit does not allege any derivative claims and includes the Partnership as a defendant rather than a nominal party. The lawsuit also omits one of the General Partner's directors, Richard Brannon, who was named in the Engel Lawsuit. The Blankman Lawsuit alleges that the General Partner's directors breached their fiduciary duties to the unitholders by failing to maximize the value of the Partnership, failing to properly value the Partnership, and ignoring conflicts of interest. The plaintiff also asserts a claim against the non-director defendants for aiding and abetting the directors' alleged breach of fiduciary duty. The Blankman Lawsuit seeks the same relief that the plaintiffs seek in the Engel Lawsuit.

On February 6, 2015, Edwin Bazini, a purported Partnership unitholder, filed a class action complaint on behalf of the Partnership's common unitholders in the United States District Court for the Northern District of Texas (the "Bazini Lawsuit"). The allegations, claims, and relief sought in the Bazini Lawsuit are nearly identical to those in the Blankman Lawsuit. On March 27, 2015, Plaintiff Bazini filed an amended complaint asserting additional claims under Sections 14(a) and 20(a) of the Securities Exchange Act of 1934.

On February 11, 2015, Mark Hinnau, a purported Partnership unitholder, filed a class action complaint on behalf of the Partnership's common unitholders in the United States District Court for the Northern District of Texas (the "Hinnau Lawsuit"). The allegations, claims, and relief sought in the Hinnau Lawsuit are nearly identical to those in the Blankman Lawsuit.

On February 11, 2015, Stephen Weaver, a purported Partnership unitholder, filed a class action complaint on behalf of the Partnership's common unitholders in the United States District Court for the Northern District of Texas (the "Weaver Lawsuit"). The allegations, claims, and relief sought in the Weaver Lawsuit are nearly identical to those in the Blankman Lawsuit.

On February 11, 2015, Adrian Dieckman, a purported Partnership unitholder, filed a class action complaint on behalf of the Partnership's common unitholders in the United States District Court for the Northern District of Texas (the "Dieckman Lawsuit"). The allegations, claims, and relief sought in the Dieckman Lawsuit are similar to those in the Blankman Lawsuit, except that the Dieckman Lawsuit does not assert an aiding and abetting claim.

On February 13, 2015, Irwin Berlin, a purported Partnership unitholder, filed a class action complaint on behalf of the Partnership's common unitholders in the United States District Court for the Northern District of Texas (the "Dieckman Lawsuit"). The allegations, claims, and relief sought in the Berlin Lawsuit are similar to those in the Blankman Lawsuit.

On March 13, 2015, the Court in the 95th Judicial District Court of Dallas County, Texas transferred and consolidated the Yeager and Coggia Lawsuits into the Engel Lawsuit and captioned the consolidated lawsuit as Engel v. Regency GP, LP, et al. (the "Consolidated State Lawsuit").

On March 30, 2015, Leonard Cooperman, a purported Partnership unitholder, filed a class action complaint on behalf of the Partnership's common unitholders in the United States District Court for the Northern District of Texas (the

“Cooperman Lawsuit”). The allegations, claims, and relief sought in the Cooperman Lawsuit are similar to those in the Blankman Lawsuit.

On March 31, 2015, the Court in United States District Court for the Northern District of Texas consolidated the Blankman, Bazini, Hinnau, Weaver, Dieckman, and Berlin Lawsuits into a consolidated lawsuit captioned Bazini v. Bradley, et al. (the “Consolidated

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Federal Lawsuit”). On April 1, 2015, plaintiffs in the Consolidated Federal Lawsuit filed an Emergency Motion to Expedite Discovery. On April 9, 2015, by order of the Court, the parties submitted a joint submission wherein defendants opposed plaintiffs request to expedite discovery. On April 17, 2015, the Court denied plaintiffs’ motion to expedite discovery.

Each of these lawsuits is at a preliminary stage. The Partnership cannot predict the outcome of these or any other lawsuits that might be filed, nor can we predict the amount of time and expense that will be required to resolve these lawsuits. The Partnership and the other defendants named in the lawsuits intend to defend vigorously against these and any other actions.

NMED Settlement. In April 2015, our subsidiary, Regency Field Services LLC (“RFS”) entered into a Settlement Agreement (“Agreement”) with the New Mexico Environment Department (“NMED”), settling and resolving the penalty assessment issued by the NMED concerning alleged violations New Mexico air regulations related to the Jal #3 and Jal #4 facilities. Pursuant to the Agreement, RFS agreed to pay a $1.2 million civil penalty to settle the alleged violations.

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. In addition, the Partnership has reclamation and bonding requirements with respect to certain un-leased and inactive coal properties. The table below reflects the undiscounted environmental liabilities recorded at March 31, 2015 and December 31, 2014. 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, 2015	December 31, 2014
Current	$2	$2
Noncurrent	7	8
Total environmental liabilities	$9	$10

The Partnership recorded less than $1 million in expenditures related to environmental remediation for the three months ended March 31, 2015.

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

8. RELATED PARTY TRANSACTIONS

As of March 31, 2015 and December 31, 2014, details of the Partnership’s related party receivables and related party payables were as follows:

	March 31, 2015	December 31, 2014
Related party receivables		
ETE and its subsidiaries	$73	$43
HPC	1	1
Ranch JV	—	1
Other	2	—
Total related party receivables	$76	$45
Related party payables		
ETE and its subsidiaries	$22	$50
HPC	3	3
Mi Vida JV	—	11
Total related party payables	$25	$64

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Transactions with ETE and its subsidiaries. Under the service agreement with Services Co., the Partnership paid Services Co.'s direct expenses for services performed, plus an annual fee of $10 million, and received the benefit of any cost savings recognized for these services. The service agreement has a five year term ending May 26, 2015, subject to earlier termination rights in the event of a change in control, the failure to achieve certain cost savings for the Partnership or upon an event of default. On April 30, 2013, this agreement was amended to provide for a waiver of the $10 million annual fee effective as of May 1, 2013 through and including April 30, 2015 and to clarify the scope and expenses chargeable as direct expenses thereunder.

On April 30, 2013, the Partnership entered into the second amendment (the "Operation and Service Amendment") to the Operation and Service Agreement (the "Operation and Service Agreement"), by and among the Partnership, ETC, the General Partner and RGS. Under the Operation and Service Agreement, ETC performs certain operations, maintenance and related services reasonably required to operate and maintain certain facilities owned by the Partnership, and the Partnership reimburses ETC for actual costs and expenses incurred in connection with the provision of these services based on an annual budget agreed upon by both parties.

The Partnership incurred total service fees related to the agreements described above from ETE and its subsidiaries of $2 million and $1 million for the three months ended March 31, 2015 and 2014.

In conjunction with distributions by the Partnership to the limited and general partner interests, ETE and its subsidiaries received cash distributions of $55 million and $32 million for the three months ended March 31, 2015 and 2014, 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 $36 million and $9 million during the three months ended March 31, 2015 and 2014, respectively.

Transactions with Lone Star. The Partnership entered into various agreements to sell NGLs to Lone Star. For the three months ended March 31, 2015 and 2014, the Partnership had recorded $121 million and $50 million, respectively, in NGL sales under these contracts. For the three months ended March 31, 2015 and 2014, the Partnership recorded $13 million and $7 million, respectively, in gathering and transportation fees with Lone Star.

9. 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, the gathering and disposing of salt water, and natural gas and NGL marketing and trading. This segment also includes the Partnership's 60% membership interest in 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, the Partnership's 50% interest in Sweeny JV, which operates a natural gas gathering facility in south Texas, the Partnership's 51% membership interest in Aqua - PVR, which transports and supplies fresh water to natural gas producers in the Marcellus shale in Pennsylvania, the Partnership's 75% membership interest in ORS, which will operate a natural gas gathering system in the Utica shale in Ohio, and the Partnership's 50% interest in Mi Vida JV, which will operate a cryogenic processing plant and related facilities in west Texas.
- 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 NGL pipelines, storage, fractionation and processing facilities located in Texas, New Mexico, 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.

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- Natural Resources. The Partnership is involved in the management of coal and natural resources properties and the related collection of royalties, and the operation of end-user coal handling facilities. 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.
- 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, Mi Vida JV and Sweeny JV) 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, 2015	2014
External Revenues		
Gathering and Processing	$887	$793
Natural Gas Transportation	—	—
NGL Services	—	—
Contract Services	84	63
Natural Resources	25	2
Corporate	3	5
Eliminations	—	—
Total	$999	$863
Intersegment Revenues		
Gathering and Processing	$—	$—
Natural Gas Transportation	—	—
NGL Services	—	—
Contract Services	1	4
Natural Resources	—	—
Corporate	—	—
Eliminations	(1)	(4)
Total	$—	$—
Segment Margin		
Gathering and Processing	$261	$166
Natural Gas Transportation	—	—
NGL Services	—	—
Contract Services	70	56
Natural Resources	25	2
Corporate	3	5
Eliminations	(1)	(4)
Total	$358	$225
Operation and Maintenance		
Gathering and Processing	$107	$60
Natural Gas Transportation	—	—
NGL Services	—	—
Contract Services	22	20
Natural Resources	4	—
Corporate	1	2
Eliminations	(1)	(4)
Total	$133	$78

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

	Three Months Ended March 31,	
	2015	2014
Total segment margin	$358	$225
Operation and maintenance	(133)	(78)
General and administrative	(36)	(33)
Gain on asset sales, net	—	2
Depreciation, depletion and amortization	(158)	(94)
Income from unconsolidated affiliates	50	43
Interest expense, net	(82)	(56)
Other income and deductions, net	3	2
Income before income taxes	$2	$11

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

Total Assets	March 31, 2015	December 31, 2014
Gathering and Processing	$12,290	$12,069
Natural Gas Transportation	1,105	1,119
NGL Services	1,217	1,162
Contract Services	2,089	2,035
Natural Resources	525	529
Corporate and Others	190	189
Total	$17,416	$17,103

Investments in Unconsolidated Affiliates	March 31, 2015	December 31, 2014
Gathering and Processing	$163	$139
Natural Gas Transportation	1,104	1,117
NGL Services	1,217	1,162
Total	$2,484	$2,418

10. 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 $4 million and $2 million was recorded in general and administrative expense for the three months ended March 31, 2015 and 2014, respectively.

Phantom Units. Phantom units granted during the period were service condition grants that (1) have graded vesting over five years or (2) vest over the next five years on a cliff basis; by vesting 60% at the end of the third year of service and vesting the remaining 40% at the end of the fifth year of service. Distributions related to the unvested phantom units are paid concurrent with the Partnership’s distribution for common units.

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The following table presents phantom units activity for the three months ended March 31, 2015:

Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at beginning of period	2,167,720	$ 24.31
Service condition grants	14,911	24.28
Vested service condition	(1,126)	24.19
Forfeited service condition	(9,329)	25.03
Outstanding at end of period	2,172,176	$ 24.37

The Partnership expects to recognize $39 million of compensation expense related to non-vested phantom units over a weighted-average period of 3.7 years.

Cash Restricted Units. Cash restricted units awards are service condition (time-based) grants of notional units that vest 100% after the third year of continued employment. A cash restricted unit entitles the award recipient to receive cash equal to the market price of one Regency common unit as of the vesting date.

The following table presents cash restricted unit activity for the three months ended March 31, 2015:

Cash Restricted Units	Units
Outstanding at beginning of period	379,328
Service condition grants	—
Vested service condition	—
Forfeited service condition	(7,410)
Outstanding at end of period	371,918

The Partnership expects to recognize $6 million of unit-based compensation expense related to non-vested cash restricted units over a period of 2.4 years.

11. 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.

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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, 2015			Fair Value Measurements at December 31, 2014		
	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	$22	$22	$—	$ 26	$ 26	$ —
NGLs	17	17	—	23	23	—
Condensate	35	35	—	36	36	—
Total Assets	$74	$74	$—	$ 85	$ 85	$ —
Liabilities						
Commodity Derivatives:						
Natural Gas	$—	$—	$—	$ —	$ —	$ —
NGLs	—	—	—	—	—	—
Condensate	1	1	—	—	—	—
Embedded derivatives in Series A Preferred Units	14	—	14	16	—	16
Total Liabilities	$15	$1	$14	$ 16	$ —	$ 16

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, 2015
Credit Spread	3.51 %

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.

The following table presents the changes in Level 3 derivatives measured on a recurring basis for the three months ended March 31, 2015. There were no transfers between the fair value hierarchy levels for the three months ended March 31, 2015.

	Embedded Derivatives in Series A Preferred Units
Net liability balance at December 31, 2014	$16
Change in fair value recorded in other income and deductions	(2)
Net liability balance at March 31, 2015	$14

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, 2015 were $5.4 billion and $5.1 billion, respectively. As of December 31, 2014, the aggregate fair value and carrying amount of the Senior Notes were $5.1 billion. The fair value of the Senior Notes is a Level 1 valuation based on third party market value quotations.

12. CONSOLIDATING GUARANTOR FINANCIAL INFORMATION

ELG, Aqua - PVR, and ORS do not fully and unconditionally guarantee, on a joint and several basis, the Senior Notes issued and outstanding as of March 31, 2015, by the Partnership and Finance Corp. Included in the Parent financial statements are the Partnership's intercompany investments in all consolidated subsidiaries and the Partnership's investments in unconsolidated affiliates. ELG, Aqua - PVR, and ORS are included in the non-guarantor subsidiaries.

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

	March 31, 2015				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
ASSETS					
Cash	$—	$—	$ 66	$(7)	$59
All other current assets	—	596	9	(1)	604
Property, plant, and equipment, net	—	9,186	437	(83)	9,540
Investments in subsidiaries	19,633	—	—	(19,633)	—
Investments in unconsolidated affiliates	—	2,283	—	201	2,484
All other assets	—	4,729	—	—	4,729
TOTAL ASSETS	$19,633	$16,794	$ 512	$(19,523)	$17,416
LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST					
All other current liabilities	—	627	21	(5)	643
Long-term liabilities	5,181	2,160	1	—	7,342
Noncontrolling interest	—	—	—	155	155
Total partners' capital	14,452	14,007	490	(19,673)	9,276
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$19,633	$16,794	$ 512	$(19,523)	$17,416

	December 31, 2014				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
ASSETS					
Cash	$—	$—	$ 32	$(8)	$24
All other current assets	—	667	13	(1)	679
Property, plant, and equipment, net	—	8,948	353	(84)	9,217
Investments in subsidiaries	19,829	—	—	(19,829)	—
Investments in unconsolidated affiliates	—	2,252	—	166	2,418
All other assets	—	4,765	—	—	4,765
TOTAL ASSETS	$19,829	$16,632	$ 398	$(19,756)	$17,103
LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST					
All other current liabilities	—	723	34	(1)	756
Long-term liabilities	5,185	1,575	6	(4)	6,762
Noncontrolling interest	—	—	—	120	120
Total partners' capital	14,644	14,334	358	(19,871)	9,465
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$19,829	$16,632	$ 398	$(19,756)	$17,103

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	Three Months Ended March 31, 2015				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$—	$982	$ 17	$—	$999
Operating costs, expenses, and other	—	961	9	(2)	968
Operating income	—	21	8	2	31
Income from unconsolidated affiliates	—	50	—	—	50
Interest expense, net	(76)	(6)	—	—	(82)
Equity in consolidated subsidiaries	74	—	—	(74)	—
Other income and deductions, net	2	1	—	—	3
Income before income taxes	—	66	8	(72)	2
Income tax expense	5	—	—	—	5
Net (loss) income	(5)	66	8	(72)	(3)
Net income attributable to noncontrolling interest	—	—	—	(4)	(4)
Net (loss) income attributable to Regency Energy Partners LP	$(5)	$66	$ 8	$(76)	$(7)
Total other comprehensive income	$—	$—	$ —	$—	$—
Comprehensive (loss) income	(5)	66	8	(72)	(3)
Comprehensive income attributable to noncontrolling interest	—	—	—	4	4
Comprehensive (loss) income attributable to Regency Energy Partners LP	$(5)	$66	$ 8	$(76)	$(7)

	Three Months Ended March 31, 2014				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$—	$848	$ 15	$—	$863
Operating costs, expenses, and other	—	834	7	—	841
Operating income	—	14	8	—	22
Income from unconsolidated affiliates	—	43	—	—	43
Interest expense, net	(49)	(7)	—	—	(56)
Equity in consolidated subsidiaries	51	—	—	(51)	—
Other income and deductions, net	(1)	3	—	—	2
Income before income taxes	1	53	8	(51)	11
Income tax (benefit) expense	—	(2)	1	—	(1)
Net income	1	55	7	(51)	12
Net income attributable to noncontrolling interest	—	(3)	—	—	(3)
Net income attributable to Regency Energy Partners LP	$1	$52	$ 7	$(51)	$9
Total other comprehensive income	$—	$—	$ —	$—	$—
Comprehensive income	1	55	7	(51)	12
Comprehensive income attributable to noncontrolling interest	—	3	—	—	3
Comprehensive income attributable to Regency Energy Partners LP	$1	$52	$ 7	$(51)	$9

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	Three Months Ended March 31, 2015				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows from operating activities	$—	$108	$ 8	$6	$122
Cash flows from investing activities	—	(449)	(100)	26	(523)
Cash flows from financing activities	—	341	126	(31)	436
Change in cash	—	—	34	1	35
Cash at beginning of period	—	—	32	(8)	24
Cash at end of period	$—	$—	$ 66	$(7)	$59

	Three Months Ended March 31, 2014				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows from operating activities	$—	$168	$ 18	$1	$187
Cash flows from investing activities	—	(451)	(3)	—	(454)
Cash flows from financing activities	—	283	(21)	(1)	261
Change in cash	—	—	(6)	—	(6)
Cash at beginning of period	—	—	19	—	19
Cash at end of period	$—	$—	$ 13	$—	$13

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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, 2014.

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; the gathering and disposing of salt water; natural gas and NGL marketing and trading; 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, West Virginia, Pennsylvania, Ohio, California, Mississippi, Alabama, New Mexico and the mid-continent region of the United States, which includes Kansas, Colorado and Oklahoma.

RECENT DEVELOPMENTS.

Merger with ETP. On April 30, 2015, we merged with a wholly-owned subsidiary of ETP, with the Partnership continuing as the surviving entity and becoming a wholly-owned subsidiary of ETP (the "Merger"). At the effective time of the Merger (the "Effective Time"), each Partnership common unit and Class F unit converted into the right to receive 0.4124 ETP common units. Based on the Partnership units outstanding, ETP issued approximately 172.2 million ETP Common Units to the Partnership's unitholders, including approximately 15.5 million units issued to ETP subsidiaries. Series A Preferred Units converted into the right to receive a preferred unit representing a limited partner interest in ETP, a new class of units in ETP established at the Effective Time. The merger was a combination of entities under common control; therefore, the carrying amounts of the Partnership's assets and liabilities will not be adjusted.

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 of oil (crude and/or condensate, a lighter oil) received from producers, the gathering and disposing of salt water, and natural gas and NGL marketing and trading. This segment also includes our 60% membership interest in 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, our 50% interest in Sweeny JV, which operates a natural gas gathering facility in south Texas, our 51% membership interest in Aqua - PVR, which transports and supplies fresh water to natural gas producers in the Marcellus shale in Pennsylvania, our 75% membership interest in ORS, which will operate a natural gas gathering system in the Utica shale in Ohio, and our 50% interest in Mi Vida JV, which will operate a cryogenic processing plant and related facilities in west Texas.
- 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 NGL 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, dehydration and BTU management.

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- Natural Resources. We are involved in the management of coal and natural resources properties and the related collection of royalties, and the operation of end-user coal handling facilities. 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.
- 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, Mi Vida JV and Sweeny JV) 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, the 25% ORS margin attributable to the holder of the noncontrolling interest, and our 33.33% portion of Ranch JV margin. Our adjusted total segment margin equals the sum of our operating segments' adjusted segment margins or segment margins, including intersegment eliminations. Adjusted segment margin and adjusted total segment margin are included as supplemental disclosures because they are primary performance measures used by management as they represent the results of product purchases and sales, a key component of our operations.
Revenue Generating Horsepower. Revenue generating horsepower is the primary driver for revenue growth in our Contract Services segment, and it is also the primary measure for evaluating our operational efficiency. Revenue generating horsepower is the total horsepower that our Contract Services segment owns and operates for external customers. It does not include horsepower under contract that is not generating revenue or idle horsepower.
Coal Royalty Tonnage. Coal royalty tonnage is the primary driver of the value of our coal royalty revenues in our Natural Resources segment. We earn most of our coal royalty revenues under long-term leases that generally require our lessees to make royalty payments to us based on the higher of a percentage of the gross sales price or a fixed price per ton of coal they sell. The balance of our coal royalty revenue 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;
- (gain) loss on debt refinancing;
- other non-cash (income) expense, net;
- our interest in ELG and ORS adjusted EBITDA less adjusted EBITDA attributable to ELG and ORS; 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, depletion and amortization expense. Because we have borrowed money to finance our operations, interest expense is a necessary element of our costs and our ability to generate cash available for distribution. Because we use capital assets, depreciation, depletion and amortization are also necessary elements of our costs. Therefore, any measures that exclude these elements have material limitations. To compensate for these limitations, we believe that it is important to consider both net earnings determined under GAAP, as well as EBITDA and adjusted EBITDA, to evaluate our performance.

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

Reconciliation of “Adjusted EBITDA” to net cash flows provided by operating activities and net (loss) income	Three Months Ended March 31, 2015	2014
Net cash flows provided by operating activities	$122	$187
Add (deduct):		
Depreciation, depletion and amortization, including debt issuance cost amortization and bond premium write-off and amortization	(158)	(97)
Income from unconsolidated affiliates	50	43
Derivative valuation change	(9)	(17)
Gain (loss) on asset sales, net	—	2
Unit-based compensation expenses	(4)	(2)
Trade accounts receivable and related party receivables	(64)	21
Other current assets and other current liabilities	(35)	(35)
Trade accounts payable and related party payables	149	(48)
Distributions of earnings received from unconsolidated affiliates	(52)	(43)
Cash flow changes in other assets and liabilities	(2)	1
Net (loss) income	(3)	12
Add (deduct):		
Interest expense, net	82	56
Depreciation, depletion and amortization expense	158	94
Income tax expense (benefit)	5	(1)
EBITDA	242	161
Add (deduct):		
Partnership’s interest in unconsolidated affiliates’ adjusted EBITDA	78	75
Income from unconsolidated affiliates	(50)	(43)
Non-cash gain from commodity and embedded derivatives	9	4
Other expense, net	3	8
Adjusted EBITDA	$282	$205

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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, 2015 and 2014 (The adjusted EBITDA for our investments in Aqua - PVR and Coal Handling is from March 21, 2014 (the acquisition date) to March 31, 2014 was not material):

	Three Months Ended March 31, 2015					
	HPC	MEP	Lone Star	Ranch JV	Aqua - PVR	Total
Net income (loss)	$19	$23	$97	$5	$(2)	
Add:						
Depreciation and amortization	9	17	29	1	1	
Interest expense, net	3	8	(1)	—	—	
Adjusted EBITDA	31	48	125	6	(1)	
Ownership interest	49.99 %	50 %	30 %	33.33 %	51 %	
Partnership's interest in adjusted EBITDA	$15	$24	$38	$2	$(1)	$78

	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

The following table presents a reconciliation of total segment margin and adjusted total segment margin to net (loss) income for the three months ended March 31, 2015 and 2014 for the Partnership:

	Three Months Ended March 31,	
	2015	2014
Net (loss) income	$(3)	$12
Add (deduct):		
Operation and maintenance	133	78
General and administrative	36	33
Gain on asset sales, net	—	(2)
Depreciation, depletion and amortization	158	94
Income from unconsolidated affiliates	(50)	(43)
Interest expense, net	82	56
Other income and deductions, net	(3)	(2)
Income tax expense (benefit)	5	(1)
Total segment margin	358	225
Add (deduct):		
Non-cash loss from commodity derivatives	11	3
Segment margin related to noncontrolling interests of ELG	(7)	(6)
Segment margin related to ownership percentage in Ranch JV	3	3
Adjusted total segment margin	$365	$225

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RESULTS OF OPERATIONS

Three Months Ended March 31, 2015 vs. Three Months Ended March 31, 2014

	Three Months Ended March 31,			
	2015	2014	Change	Percent
Total revenues	$999	$863	$136	16 %
Cost of sales	641	638	(3)	—
Total segment margin (1)	358	225	133	59
Operation and maintenance	133	78	(55)	71
General and administrative	36	33	(3)	9
Gain on asset sales, net	—	(2)	(2)	100
Depreciation, depletion and amortization	158	94	(64)	68
Operating income	31	22	9	41
Income from unconsolidated affiliates	50	43	7	16
Interest expense, net	(82)	(56)	(26)	46
Other income and deductions, net	3	2	1	50
Income before income taxes	2	11	(9)	82
Income tax expense (benefit)	5	(1)	(6)	600
Net (loss) income	(3)	12	(15)	125
Net income attributable to noncontrolling interest	(4)	(3)	(1)	33
Net (loss) income attributable to Regency Energy Partners LP	$(7)	$9	$(16)	178
Gathering and processing segment margin	$261	$166	$95	57
Non-cash loss from commodity derivatives	11	3	8	267
Segment margin related to noncontrolling interests of ELG	(7)	(6)	(1)	17
Segment margin related to ownership percentage in Ranch JV	3	3	—	—
Adjusted gathering and processing segment margin	268	166	102	61
Contract services segment margin (2)	70	56	14	25
Natural resources segment margin	25	2	23	1,150
Corporate segment margin	3	5	(2)	40
Intersegment eliminations (2)	(1)	(4)	3	75
Adjusted total segment margin	$365	$225	$140	62 %

(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 $1 million and $4 million for the three months ended March 31, 2015 and 2014, respectively. These intersegment revenues were eliminated upon consolidation.

Net (Loss) Income Attributable to Regency Energy Partners LP. We recorded net loss of $7 million for the three months ended March 31, 2015 compared to net income of $9 million for the three months ended March 31, 2014. The major components of this change were as follows:

- $133 million increase in total segment margin primarily due to a $127 million contribution in segment margin from the PVR and Eagle Rock acquisitions, including a $23 million contribution from the Natural Resources segment, and a $14 million increase in the Contract Services segment related to an increase in revenue generating horsepower, offset by a decrease in segment margin from the Permian region related to the decline in commodity prices;
- $7 million increase in income from unconsolidated subsidiaries primarily related to an increase in volumes fractionated at Lone Star Fractionator II and an increase in volumes transported from west Texas; offset by

- $64 million increase in depreciation, depletion and amortization primarily due to the increase in property, plant, and equipment and intangible assets associated with the PVR and Eagle Rock acquisitions;
- $55 million increase in operation and maintenance expense primarily due to the PVR and Eagle Rock acquisitions and organic growth in south and west Texas;

- $26 million increase in interest expense, net primarily due to $15 million in interest expense related to the senior notes assumed in the PVR acquisition, and $18 million in interest expense related to the senior notes assumed in the Eagle Rock acquisition; and
- $3 million increase in general and administrative expenses primarily due to higher employee expenses.

Adjusted Total Segment Margin. Adjusted total segment margin increased to $365 million in the three months ended March 31, 2015 from $225 million in the three months ended March 31, 2014. The major components of this change were as follows:

- Adjusted Gathering and Processing segment margin increased to $268 million during the three months ended March 31, 2015 from $166 million for the three months ended March 31, 2014 primarily due to $104 million contribution from the PVR and Eagle Rock acquisitions, including $29 million contribution from Eagle Rock, offset by a decrease in segment margin from the Permian region related to the decline in commodity prices. Total Gathering and Processing throughput increased to 5,756,000 MMBtu/d during the three months ended March 31, 2015, including 3,005,000 MMBtu/d from the PVR and Eagle Rock acquisitions, from 2,662,000 MMBtu/d during the three months ended March 31, 2014. Total NGL gross production increased to 168,000 Bbls/d during the three months ended March 31, 2015 from 101,000 Bbls/d during the three months ended March 31, 2014;
- Natural Resources segment margin was $25 million during the three months ended March 31, 2015. Coal royalty tonnage for the same period was 3,240,000, for an average royalty per ton of $4.25; and
- Contract Services segment margin increased to $70 million during the three months ended March 31, 2015 from $56 million for the three months ended March 31, 2014. As of March 31, 2015 and 2014, total revenue generating horsepower was 1,338,000 and 1,120,000, inclusive of 2,000 and 47,000, respectively, of revenue generating horsepower utilized by our Gathering and Processing segment.

Operation and Maintenance. Operation and maintenance expense increased to $133 million in the three months ended March 31, 2015 from $78 million during the three months ended March 31, 2014. The change was primarily due to the following:

- $26 million increase in pipeline and plant maintenance and materials expenses primarily due to organic growth in south and west Texas as well as the PVR and Eagle Rock acquisitions;
- $21 million increase in employee expenses related to an increase in headcount from the PVR and Eagle Rock acquisitions;
- $4 million increase in ad valorem taxes due to the PVR and Eagle Rock acquisitions;
- $2 million increase in utilities expenses primarily due to organic growth in south and west Texas as well as the additional facilities related to the PVR and Eagle Rock Eagle Rock acquisitions; and
- $2 million in royalty expenses expenses related to the Natural Resources segment.

General and Administrative. General and administrative expense increased to $36 million in the three months ended March 31, 2015 from $33 million in the three months ended March 31, 2014 primarily due to a $9 million increase in employee costs and a $2 million increase in bad debt expense offset by an $8 million decrease due to lower acquisitions costs.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased to $158 million in the three months ended March 31, 2015 from $94 million in the three months ended March 31, 2014, primarily due to the completion of various organic growth projects since April 2014 and assets acquired from PVR and Eagle Rock.

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Income from Unconsolidated Affiliates. Income from unconsolidated affiliates increased to $50 million for the three months ended March 31, 2015 from $43 million for the three months ended March 31, 2014. The schedule below summarizes the components of income from unconsolidated affiliates and our ownership interest for the three months ended March 31, 2015 and 2014, respectively:

	Three Months Ended March 31, 2015					
	HPC	MEP	Lone Star	Ranch JV	Aqua - PVR	Total
Net income (loss)	$19	$23	$97	$5	$(2)	
Ownership interest	49.99%	50%	30%	33.33%	51%	
Share of unconsolidated affiliates' net income (loss)	9	12	29	2	(1)	
Less: Amortization of excess fair value of unconsolidated affiliates	(1)	—	—	—	—	
Income (loss) from unconsolidated affiliates	$8	$12	$29	$2	$(1)	$50

	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 (loss)	7	11	25	2	(1)	
Less: Amortization of excess fair value of unconsolidated affiliates	(1)	—	—	—	—	
Income (loss) from unconsolidated affiliates	$6	$11	$25	$2	$(1)	$43

HPC's net income increased to $19 million for the three months ended March 31, 2015 from $15 million for the three months ended March 31, 2014, primarily due to lower general and administrative expenses and higher revenues. MEP's net income increased to $23 million for the three months ended March 31, 2015 from $21 million for the three months ended March 31, 2014. Lone Star's net income increased to $97 million for the three months ended March 31, 2015 from $83 million for the three months ended March 31, 2014, primarily due to an increase in fractionated volumes of 66,000 BPD period over period as we commissioned Fractionator II in October 2013 and ramped up volumes to capacity. Additionally, a 33,000 BPD increase in transported volumes on our pipeline system increased net income for the current period as compared to the prior year period.

The following table presents operational data for each of our unconsolidated affiliates for the three months ended March 31, 2015 and 2014 that we owned as of both dates:

		Three Months Ended March 31,	
	Operational data	2015	2014
HPC	Throughput (MMBtu/d)	773,000	613,000
MEP	Throughput (MMBtu/d)	1,302,000	1,268,000
Lone Star	NGL Transportation — Total Volumes (Bbls/d)	225,000	184,000
	Refinery — Geismar Throughput (Bbls/d)	14,000	11,000
	Fractionation — Throughput Volume (Bbls/d)	203,000	135,000
Ranch JV	Throughput (MMBtu/d)	144,000	120,000

Interest Expense, Net. Interest expense, net increased to $82 million for the three months ended March 31, 2015 from $56 million for the three months ended March 31, 2014, primarily due to $15 million in interest expense related to the senior notes assumed in the PVR Acquisition, and $18 million in interest expense related to the senior notes assumed in the Eagle Rock acquisition.

Other Income and Deductions, Net. Other income and deductions increased to a $3 million gain from a $2 million gain for the three months ended March 31, 2015 and 2014, respectively, primarily due to a non-cash gain on the embedded derivative related to the Series A Preferred Units.

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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, 2014.

OTHER MATTERS

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

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

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 surplus of $20 million at March 31, 2015 compared to a working capital deficit of $53 million at December 31, 2014. The increase in the working capital was primarily due to a $27 million increase in cash and cash equivalents, net of drafts payable.

Cash Flows from Operating Activities. Net cash flows provided by operating activities decreased to $122 million in the three months ended March 31, 2015 from $187 million in the three months ended March 31, 2014, primarily as a result of changes in current assets and liabilities.

Cash Flows used in Investing Activities. Net cash flows used in investing activities was $523 million in the three months ended March 31, 2015 compared to cash used in investing activities of $454 million in the three months ended March 31, 2014 primarily due to an increase in capital expenditures related to organic growth projects and capital contributions to unconsolidated affiliates, offset by no cash spent on acquisitions in the quarter ended March 31, 2015.

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, 2015, we incurred $531 million of growth capital expenditures, inclusive of contributions to unconsolidated affiliates. Growth capital expenditures for the three months ended March 31, 2015 were primarily related to $325 million for our Gathering and Processing segment, $93 million for our NGL Services segment, and $113 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, 2015, we incurred $22 million of maintenance capital expenditures.

Cash Flows from Financing Activities. Net cash flows provided by financing activities increased to $436 million in the three months ended March 31, 2015 from cash flow provided by financing activities of $261 million during the same period in 2014 primarily due to higher borrowings under the revolving credit facility, offset by higher Partner distributions.

Capital Resources

Equity Distribution Agreement. During the three months ended March 31, 2015, we received net proceeds of $34 million from common units sold pursuant to an equity distribution agreement which were used for general partnership purposes. We did not issue any common units under the equity distribution agreement subsequent to March 31, 2015, and the equity distribution agreement terminated as a result of the ETP Merger in April 2015.

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Revolving Credit Facility. On April 30, 2015, in connection with the Merger, the revolving credit facility was paid off in full and terminated. As a result, compliance with material covenants is no longer applicable as of the reporting date.
Cash Distributions from Unconsolidated Affiliates. The following table summarizes the cash distributions from unconsolidated affiliates for the three months ended March 31, 2015 and 2014:

	Three Months Ended March 31,	
	2015	2014
HPC	$13	$10
MEP	20	18
Lone Star	37	25
Ranch JV	3	—
	$73	$53

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK
Risk and Accounting Policies. We are exposed to market risks associated with commodity prices, counterparty credit and interest rates. Our management and the board of directors of our General Partner have established comprehensive risk management policies and procedures to monitor and manage these market risks. Our General Partner is responsible for delegation of transaction authority levels, and the Audit and Risk Committee of our General Partner is responsible for the oversight of credit risk and commodity price risk, including monitoring exposure limits. The Audit and Risk Committee receives regular briefings on positions and exposures, credit exposures and overall risk management in the context of market activities.
Commodity Price Risk. We are a net seller of NGLs, condensate and natural gas as a result of our gathering and processing operations. The prices of these commodities are impacted by changes in supply and demand as well as market forces. Our profitability and cash flow are affected by the inherent volatility of these commodities, which could adversely affect our ability to make distributions to our unitholders. We manage this commodity price exposure through an integrated strategy that includes management of our contract portfolio, matching sales prices of commodities with purchases, optimization of our portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, we may not be able to match pricing terms or to cover our risk to price exposure with financial hedges, and we may be exposed to commodity price risk.
Through our natural gas marketing activity, we will have credit exposure to additional counterparties. We minimize the credit risk associated with natural gas marketing by limiting our exposure to any single counterparty and monitoring the creditworthiness of our counterparties on an ongoing basis. In addition, the our natural gas purchase and sale contracts, for certain counterparties, are subject to counterparty netting agreements governing settlement under such natural gas purchase and sales contracts, and when possible, we net the open positions of each counterparty.
We have swap contracts that settle against certain NGLs, condensate and natural gas market prices.

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The following table sets forth certain information regarding our hedges outstanding at March 31, 2015. 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, 2015

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 2015 – December 2015	Propane	(523	) MBbls	Index	$ 1.05	/gallon	$12	$1
April 2015 – December 2015	Normal Butane	(220	) MBbls	Index	$ 1.19	/gallon	5	1
April 2015 – December 2016	West Texas Intermediate Crude	(1,060	) MBbls	Index	$ 87.56	/Bbl	34	6
April 2015 – December 2015	Natural Gas	(17,875,000	) MMBtu	Index	$ 3.86	/MMBtu	22	5
					Total Fair Value		$73	

* 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, 2015.

There have been no changes in our internal controls over financial reporting (as defined in Rule 13(a)–15(f) or Rule 15d–15(f) of the Exchange Act) during the three months ended March 31, 2015 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II – OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

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

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, 2014. There are no material changes from the risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2014.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

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Item 6. EXHIBITS

Exhibit Number	Description	Incorporated by Reference from Form	Date Filed and File No
1.1	Equity distribution agreement with Wells Fargo Securities, LLC, Barclays Capital Inc., BNP Paribas Securities Corp., Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., Goldman, Sachs & Co., J.P. Morgan Securities LLC, Jefferies LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Mitsubishi UFJ Securities (USA) Inc., Morgan Stanley & Co. LLC, RBC Capital Markets, LLC, Scotia Capital (USA), Inc., SunTrust Robinson Humphrey, Inc., UBS Securities LLC and USCA Securities LLC.	8-K	January 8, 2015
2.1	Agreement and Plan of Merger, dated as of January 25, 2015, by and among Regency Energy Partners LP, Regency GP LP, Energy Transfer Partners, L.P., Energy Transfer Partners, GP, L.P., Energy Transfer Equity, L.P.	8-K	January 26, 2015
2.2	Amendment No. 1 to Agreement and Plan of Merger, dated as of February 18, 2015, by and among Regency Energy Partners LP, Regency GP LP, Energy Transfer Partners, L.P., Energy Transfer Partners, GP, L.P., Energy Transfer Equity, L.P.	8-K	February 19, 2015
10.1	First Amendment to Seventh Amended and Restated Credit Agreement, dated as of February 24, 2015.	*	
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	*	
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	*	
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	**	
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	**	
101.INS	XBRL Instance Document.	*	
101.SCH	XBRL Taxonomy Extension Schema Document.	*	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.	*	

101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.	*
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.	*
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.	*

* Filed herewith.
** Furnished herewith.

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SIGNATURE

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

	REGENCY ENERGY PARTNERS LP
	By: Regency GP LP, its general partner
	By: Regency GP LLC, its general partner
Date: May 8, 2015	/S/ A. TROY STURROCK
	A. Troy Sturrock
	Vice President and Controller
	(Duly Authorized Officer)