Enable Midstream Partners, LP
Form 10-Q
November 02, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES AND EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2016
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____to_____
Commission File No. 1-36413

ENABLE MIDSTREAM PARTNERS, LP
(Exact name of registrant as specified in its charter)

Delaware	72-1252419
(State or jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

One Leadership Square
211 North Robinson Avenue
Suite 150
Oklahoma City, Oklahoma 73102
(Address of principal executive offices)
(Zip Code)

Registrant's telephone number, including area code: (405) 525-7788

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. þ Yes ¨ 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). þ Yes ¨ 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 "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	þ	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 þ No

As of October 14, 2016, there were 214,461,760 common units and 207,855,430 subordinated units outstanding.

Table of Contents

ENABLE MIDSTREAM PARTNERS, LP
FORM 10-Q
TABLE OF CONTENTS

AVAILABLE INFORMATION

Our website is www.enablemidstream.com. On the investor relations tab of our website, http://investors.enablemidstream.com, we make available free of charge a variety of information to investors. Our goal is to maintain the investor relations tab of our website as a portal through which investors can easily find or navigate to pertinent information about us, including but not limited to:

- our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports as soon as reasonably practicable after we electronically file that material with or furnish it to the SEC;
- press releases on quarterly distributions, quarterly earnings, and other developments;
- governance information, including our governance guidelines, committee charters, and code of ethics and business conduct;
- information on events and presentations, including an archive of available calls, webcasts, and presentations; and
- news and other announcements that we may post from time to time that investors may find useful or interesting.

Information contained on our website or any other website is not incorporated by reference into this report and does not constitute a part of this report.

GLOSSARY

Adjusted EBITDA.	A non-GAAP measure calculated as net income from continuing operations before interest expense, income tax expense, depreciation and amortization expense and certain other items management believes affect the comparability of operating results.
Adjusted interest expense.	A non-GAAP measure calculated as interest expense plus amortization of premium on long-term debt and capitalized interest, less amortization of debt costs.
Annual Report.	Annual Report on Form 10-K for the year ended December 31, 2015.
ASU.	Accounting Standards Update.
Barrel.	42 U.S. gallons of petroleum products.
Bbl.	Barrel.
Bbl/d.	Barrels per day.
Bcf/d.	Billion cubic feet per day.
Btu.	British thermal unit. When used in terms of volume, Btu refers to the amount of natural gas required to raise the temperature of one pound of water by one degree Fahrenheit at one atmospheric pressure.
CenterPoint Energy.	CenterPoint Energy, Inc., a Texas corporation, and its subsidiaries, other than Enable Midstream Partners, LP for periods prior to formation of the Partnership on May 1, 2013.
Condensate.	A natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.
DCF.	Distributable cash flow, which is a non-GAAP measure calculated as Adjusted EBITDA less Series A Preferred Unit distributions, Adjusted interest expense, maintenance capital expenditures and current income taxes.
Distribution coverage ratio.	A non-GAAP measure calculated as DCF divided by distributions related to common and subordinated unitholders.
DRIP.	Distribution Reinvestment Plan entered into on June 23, 2016, which, beginning with the quarterly distribution for the quarter ended September 30, 2016, offers owners of our common and subordinated units the ability to purchase additional common units by reinvesting all or a portion of the cash distributions paid to them on their common or subordinated units.
EGT.	Enable Gas Transmission, LLC, a wholly owned subsidiary of the Partnership that operates a 5,900-mile interstate pipeline that provides natural gas transportation and storage services to customers principally in the Anadarko, Arkoma and Ark-La-Tex basins in Oklahoma, Texas, Arkansas, Louisiana and Kansas.
Enable GP.	Enable GP, LLC, a Delaware limited liability company and the general partner of Enable Midstream Partners, LP.
Enable Midstream Services.	Enable Midstream Services, LLC, a wholly owned subsidiary of Enable Midstream Partners, LP.
EOIT.	Enable Oklahoma Intrastate Transmission, LLC, formerly Enogex LLC, a wholly owned subsidiary of the Partnership that operates a 2,200-mile intrastate pipeline that provides natural gas transportation and storage services to customers in Oklahoma.
Exchange Act.	Securities Exchange Act of 1934, as amended.
FASB.	Financial Accounting Standards Board.
FERC.	Federal Energy Regulatory Commission.
Fractionation.	The separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale.
GAAP.	Generally accepted accounting principles in the United States.
Gas imbalance.	The difference between the actual amounts of natural gas delivered from or received by a pipeline, as compared to the amounts scheduled to be delivered or received.

General Partner.	Enable GP, LLC, a Delaware limited liability company, the general partner of Enable Midstream Partners, LP.
Gross margin.	A non-GAAP measure calculated as total revenues minus cost of natural gas and natural gas liquids, excluding depreciation and amortization.
LIBOR.	London Interbank Offered Rate.
March 31 Quarterly Report.	Quarterly Report on Form 10-Q for the period ended March 31, 2016.
MBbl.	Thousand barrels.

MBbl/d.	Thousand barrels per day.
MFA.	Master Formation Agreement dated as of March 14, 2013.
MMcf.	Million cubic feet of natural gas.
MMcf/d.	Million cubic feet per day.
NGLs.	Natural gas liquids, which are the hydrocarbon liquids contained within natural gas including condensate.
NYMEX.	New York Mercantile Exchange.
Offering.	Initial public offering of Enable Midstream Partners, LP.
OGE Energy.	OGE Energy Corp., an Oklahoma corporation, and its subsidiaries.
Partnership.	Enable Midstream Partners, LP, and its subsidiaries.
Partnership Agreement.	Fourth Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP dated as of June 22, 2016.
Purchase Agreement.	Purchase Agreement, dated January 28, 2016, by and between the Partnership and CenterPoint Energy, Inc. for the sale by the Partnership and purchase by CenterPoint Energy, Inc. of Series A Preferred Units.
Revolving Credit Facility.	$1.75 billion senior unsecured revolving credit facility.
SEC.	Securities and Exchange Commission.
Securities Act.	Securities Act of 1933, as amended.
Series A Preferred Units.	10% Series A Fixed-to-Floating Non-Cumulative Redeemable Perpetual Preferred Units representing limited partner interests in the Partnership.
SESH.	Southeast Supply Header, LLC, in which the Partnership owns a 50% interest, that operates an approximately 290-mile interstate natural gas pipeline from Perryville, Louisiana to southwestern Alabama near the Gulf Coast.
TBtu.	Trillion British thermal units.
TBtu/d.	Trillion British thermal units per day.
WTI.	West Texas Intermediate.
2015 Term Loan Agreement.	$450 million unsecured term loan agreement.
2019 Notes.	$500 million 2.400% senior notes due 2019.
2024 Notes.	$600 million 3.900% senior notes due 2024.
2044 Notes.	$550 million 5.000% senior notes due 2044.

2

Table of Contents

FORWARD-LOOKING STATEMENTS

Some of the information in this report may contain forward-looking statements. Forward-looking statements give our current expectations, contain projections of results of operations or of financial condition, or forecasts of future events. Words such as “could,” “will,” “should,” “may,” “assume,” “forecast,” “position,” “predict,” “strategy,” “expect,” “intend,” “p
“anticipate,” “believe,” “project,” “budget,” “potential,” or “continue,” and similar expressions are used to identify forward-loo
statements. Without limiting the generality of the foregoing, forward-looking statements contained in this report include our expectations of plans, strategies, objectives, growth and anticipated financial and operational performance, including revenue projections, capital expenditures and tax position. Forward-looking statements can be affected by assumptions used or by known or unknown risks or uncertainties. Consequently, no forward-looking statements can be guaranteed.

A forward-looking statement may include a statement of the assumptions or bases underlying the forward-looking statement. We believe that we have chosen these assumptions or bases in good faith and that they are reasonable. However, when considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this report, in our Annual Report on Form 10-K for the year ended December 31, 2015 (Annual Report) and in our Quarterly Report on Form 10-Q for the period ended March 31, 2016 (March 31 Quarterly Report). Those risk factors and other factors noted throughout this report, in our Annual Report and in our March 31 Quarterly Report could cause our actual results to differ materially from those disclosed in any forward-looking statement. You are cautioned not to place undue reliance on any forward-looking statements. You should also understand that it is not possible to predict or identify all such factors and should not consider the following list to be a complete statement of all potential risks and uncertainties. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statements include:

- changes in general economic conditions;
- competitive conditions in our industry;
- actions taken by our customers and competitors;
- the supply and demand for natural gas, NGLs, crude oil and midstream services;
- our ability to successfully implement our business plan;
- our ability to complete internal growth projects on time and on budget;
- the price and availability of debt and equity financing;
- strategic decisions by CenterPoint Energy and OGE Energy regarding their ownership of us and our General Partner;
- operating hazards and other risks incidental to transporting, storing, gathering and processing natural gas, NGLs, crude oil and midstream products;
- natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- interest rates;
- labor relations;
- large customer defaults;
- changes in the availability and cost of capital;
- changes in tax status;
- the effects of existing and future laws and governmental regulations;
- changes in insurance markets impacting costs and the level and types of coverage available;
- the timing and extent of changes in commodity prices;
- the suspension, reduction or termination of our customers’ obligations under our commercial agreements;
- disruptions due to equipment interruption or failure at our facilities, or third-party facilities on which our business is dependent;
- the effects of future litigation; and
- other factors set forth in this report and our other filings with the SEC, including our Annual Report and our March 31 Quarterly Report.

Forward-looking statements speak only as of the date on which they are made. We expressly disclaim any obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by law.

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions, except per unit data)			
Revenues (including revenues from affiliates (Note 11)):				
Product sales	$326	$357	$837	$1,043
Service revenue	294	289	821	809
Total Revenues	620	646	1,658	1,852
Cost and Expenses (including expenses from affiliates (Note 11)):				
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	268	287	717	856
Operation and maintenance	87	101	275	313
General and Administrative	21	29	68	78
Depreciation and amortization	84	84	248	233
Impairments (Note 5)	8	1,105	8	1,105
Taxes other than income taxes	13	15	43	45
Total Cost and Expenses	481	1,621	1,359	2,630
Operating Income (Loss)	139	(975)	299	(778)
Other Income (Expense):				
Interest expense (including expenses from affiliates (Note 11))	(26)	(23)	(74)	(66)
Equity in earnings of equity method affiliate	8	7	22	21
Other, net	—	—	—	2
Total Other Expense	(18)	(16)	(52)	(43)
Income Before Income Taxes	121	(991)	247	(821)
Income tax expense	2	—	3	2
Net Income (Loss)	$119	$(991)	$244	$(823)
Less: Net income (loss) attributable to noncontrolling interest	—	(6)	—	(6)
Net Income (Loss) attributable to limited partners	$119	$(985)	$244	$(817)
Less: Series A Preferred Unit distributions (Note 4)	9	—	13	—
Net Income (Loss) attributable to common and subordinated units (Note 3)	$110	$(985)	$231	$(817)
Basic earnings (loss) per unit (Note 3)				
Common units	$0.26	$(2.33)	$0.55	$(1.93)
Subordinated units	$0.26	$(2.34)	$0.55	$(1.94)
Diluted earnings (loss) per unit (Note 3)				
Common units	$0.26	$(2.33)	$0.55	$(1.93)
Subordinated units	$0.26	$(2.34)	$0.55	$(1.94)

See Notes to the Unaudited Condensed Consolidated Financial Statements

Table of Contents

ENABLE MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions)			
Net income (loss)	$119	$(991)	$244	$(823)
Comprehensive income (loss)	119	(991)	244	(823)
Less: Comprehensive income (loss) attributable to noncontrolling interest	—	(6)	—	(6)
Comprehensive income (loss) attributable to Enable Midstream Partners, LP	$119	$(985)	$244	$(817)

See Notes to the Unaudited Condensed Consolidated Financial Statements

Table of Contents

ENABLE MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2016	December 31, 2015
	(In millions)	
Current Assets:		
Cash and cash equivalents	$23	$ 4
Accounts receivable, net of allowance for doubtful accounts	278	245
Accounts receivable—affiliated companies	13	21
Inventory	42	53
Gas imbalances	20	23
Other current assets	32	35
Total current assets	408	381
Property, Plant and Equipment:		
Property, plant and equipment	11,523	11,293
Less accumulated depreciation and amortization	1,367	1,162
Property, plant and equipment, net	10,156	10,131
Other Assets:		
Intangible assets, net	313	333
Investment in equity method affiliate	326	344
Other	38	37
Total other assets	677	714
Total Assets	$11,241	$ 11,226
Current Liabilities:		
Accounts payable	$144	$ 248
Accounts payable—affiliated companies	5	9
Short-term debt	—	236
Taxes accrued	51	30
Gas imbalances	22	25
Other	116	67
Total current liabilities	338	615
Other Liabilities:		
Accumulated deferred income taxes, net	12	8
Notes payable—affiliated companies	—	363
Regulatory liabilities	19	18
Other	30	20
Total other liabilities	61	409
Long-Term Debt	3,113	2,671
Commitments and Contingencies (Note 12)		
Partners' Equity:		
Series A Preferred Units (14,520,000 issued and outstanding at September 30, 2016 and 0 issued and outstanding at December 31, 2015)	362	—
Common units (214,460,536 issued and outstanding at September 30, 2016 and 214,541,422 issued and outstanding at December 31, 2015, respectively)	3,635	3,714
Subordinated units (207,855,430 issued and outstanding at September 30, 2016 and December 31, 2015, respectively)	3,721	3,805
Noncontrolling interest	11	12
Total Partners' Equity	7,729	7,531

Total Liabilities and Partners' Equity	$11,241	$ 11,226

See Notes to the Unaudited Condensed Consolidated Financial Statements

6

Table of Contents

ENABLE MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30, 2016			2015		
	(In millions)					
Cash Flows from Operating Activities:						
Net income (loss)	$	244		$	(823	)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:						
Depreciation and amortization	248			233		
Deferred income taxes	4			1		
Impairments	8			1,105		
Loss on sale/retirement of assets	9			2		
Equity in earnings of equity method affiliate, net of distributions	—			5		
Equity based compensation	9			7		
Amortization of debt costs and discount (premium)	(2		)	(2		)
Changes in other assets and liabilities:						
Accounts receivable, net	(33		)	(37		)
Accounts receivable—affiliated companies	8			2		
Inventory	11			11		
Gas imbalance assets	3			29		
Other current assets	3			(1		)
Other assets	(1		)	(5		)
Accounts payable	(84		)	(56		)
Accounts payable—affiliated companies	(4		)	(26		)
Gas imbalance liabilities	(3		)	4		
Other current liabilities	68			45		
Other liabilities	10			(3		)
Net cash provided by operating activities	498			491		
Cash Flows from Investing Activities:						
Capital expenditures	(289		)	(654		)
	—			(80		)

Acquisitions, net of cash acquired		
Proceeds from sale of assets	1	1
Investment in equity method affiliate	—	(8)
Return of investment in equity method affiliate	18	11
Net cash used in investing activities	(270)	(730)
Cash Flows from Financing Activities:		
Proceeds from long term debt, net of issuance costs	—	450
Proceeds from revolving credit facility	838	275
Repayment of revolving credit facility	(393)	(275)
Increase (decrease) in short-term debt	(236)	179
Repayment of notes payable—affiliated companies	(363)	—
Proceeds from issuance of Series A Preferred Units, net of issuance costs	362	—
Distributions	(417)	(397)
Net cash provided by (used in) financing activities	(209)	232
Net Increase (Decrease) in Cash and Cash Equivalents	19	(7)
Cash and Cash Equivalents at Beginning of Period	4	12
Cash and Cash Equivalents at End of Period	$ 23	$ 5

See Notes to the Unaudited Condensed Consolidated Financial Statements

Table of Contents

ENABLE MIDSTREAM PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY
(Unaudited)

	Series A Preferred Units		Common Units		Subordinated Units		Noncontrolling Interest	Total Partners' Equity
	Units	Value	Units	Value	Units	Value	Value	Value
	(In millions)							
Balance as of December 31, 2014	—	$—	214	$4,353	208	$4,439	$ 31	$8,823
Net income (loss)	—	—	—	(412)	—	(405)	(6)	(823)
Issuance of common units upon interest acquisition of SESH	—	—	—	1	—	—	—	1
Distributions	—	—	—	(202)	—	(195)	—	(397)
Equity based compensation	—	—	—	7	—	—	—	7
Balance as of September 30, 2015	—	$—	214	$3,747	208	$3,839	$ 25	$7,611
Balance as of December 31, 2015	—	$—	214	$3,714	208	$3,805	$ 12	$7,531
Net income	—	13	—	117	—	114	—	244
Issuance of Series A Preferred Units	15	362	—	—	—	—	—	362
Distributions	—	(13)	—	(205)	—	(198)	(1)	(417)
Equity based compensation	—	—	—	9	—	—	—	9
Balance as of September 30, 2016	15	$362	214	$3,635	208	$3,721	$ 11	$7,729

See Notes to the Unaudited Condensed Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Organization

Enable Midstream Partners, LP (Partnership) is a large-scale, growth-oriented Delaware limited partnership formed to own, operate and develop strategically located natural gas and crude oil infrastructure assets. The Partnership's assets and operations are organized into two reportable segments: (i) Gathering and Processing, which primarily provides natural gas gathering, processing and fractionation services and crude oil gathering for our producer customers, and (ii) Transportation and Storage, which provides interstate and intrastate natural gas pipeline transportation and storage services primarily to natural gas producers, utilities and industrial customers. The natural gas gathering and processing assets are located in five states and serve natural gas production in the Anadarko, Arkoma and Ark-La-Tex basins. This segment also includes a crude oil gathering business in the Bakken Shale formation, principally located in the Williston basin. The natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

The Partnership is controlled equally by CenterPoint Energy and OGE Energy, who each have 50% of the management rights of Enable GP. Enable GP was established by CenterPoint Energy and OGE Energy to govern the Partnership and has no other operating activities. Enable GP is governed by a board made up of an equal number of representatives designated by each of CenterPoint Energy and OGE Energy, along with the independent board members CenterPoint Energy and OGE Energy mutually agreed to appoint. Based on the 50/50 management ownership, with neither company having control, CenterPoint Energy and OGE Energy do not consolidate their interests in the Partnership. CenterPoint Energy and OGE Energy also own a 40% and 60% interest, respectively, in the incentive distribution rights held by Enable GP. As of September 30, 2016, CenterPoint Energy held approximately 55.4% of the common and subordinated units in the Partnership, or 94,151,707 common units and 139,704,916 subordinated units, and OGE Energy held approximately 26.3% of the common and subordinated units in the Partnership, or 42,832,291 common units and 68,150,514 subordinated units. Additionally, CenterPoint Energy holds 14,520,000 Series A Preferred Units. See Note 4 for further information related to the Series A Preferred Units.

For the period from December 31, 2014 through June 29, 2015, the financial statements reflect a 49.90% interest in SESH. On June 12, 2015, CenterPoint Energy exercised its put right with respect to a 0.1% interest in SESH. Pursuant to the put right, on June 30, 2015, CenterPoint Energy contributed its remaining 0.1% interest in SESH to the Partnership in exchange for 25,341 common units representing limited partner interests in the Partnership. As of September 30, 2016, the Partnership owned a 50% interest in SESH. See Note 6 for further discussion of SESH.

Basis of Presentation

The accompanying condensed consolidated financial statements and related notes of the Partnership have been prepared pursuant to the rules and regulations of the SEC and GAAP. Pursuant to such rules and regulations, certain disclosures normally included in financial statements prepared in accordance with GAAP have been omitted. The accompanying condensed consolidated financial statements and related notes should be read in conjunction with the combined and consolidated financial statements and related notes included in our Annual Report.

These condensed consolidated financial statements and the related financial statement disclosures reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective periods. Amounts reported in the Partnership's Condensed Consolidated

Statements of Income are not necessarily indicative of amounts expected for a full-year period due to the effects of, among other things, (a) seasonal fluctuations in demand for energy and energy services, (b) changes in energy commodity prices, (c) timing of maintenance and other expenditures and (d) acquisitions and dispositions of businesses, assets and other interests.

For a description of the Partnership's reportable segments, see Note 14.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Table of Contents

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount and do not typically bear interest. The determination of the allowance for doubtful accounts requires management to make estimates and judgments regarding our customers' ability to pay. The allowance for doubtful accounts is determined based upon specific identification and estimates of future uncollectable amounts. On an ongoing basis, we evaluate our customers' financial strength based on aging of accounts receivable, payment history, and review of other relevant information, including ratings agency credit ratings and alerts, publicly available reports and news releases, and bank and trade references. It is the policy of management to review the outstanding accounts receivable at least quarterly, giving consideration to historical bad debt write-offs, the aging of receivables and specific customer circumstances that may impact their ability to pay the amounts due. Based on this review, management determined that a $3 million allowance for doubtful accounts was required as of September 30, 2016, and no allowance for doubtful accounts was required as of December 31, 2015.

Third Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP

On February 18, 2016, in connection with the closing of the private placement of 14,520,000 Series A Preferred Units and pursuant to the Purchase Agreement, the General Partner adopted the Third Amended and Restated Agreement of Limited Partnership which, among other things, authorized and established the terms of the Series A Preferred Units and the other series of preferred units that are issuable upon conversion of the Series A Preferred Units. For further information related to the issuance of the Series A Preferred Units, see Note 4.

Fourth Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP

On June 22, 2016, the General Partner adopted the Fourth Amended and Restated Agreement of Limited Partnership (the Partnership Agreement), which changed the last permitted distribution date with respect to each fiscal quarter from 45 days following the close of such quarter to 60 days following the close of such quarter.

(2) New Accounting Pronouncements

Revenue from Contracts with Customers

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)," which supersedes the revenue recognition requirements in "Revenue Recognition (Topic 605)," and requires entities to recognize revenue in a way that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to in exchange for those goods or services. In August 2015, the FASB issued ASU No. 2015-14, "Revenue from Contracts with Customers (Topic 606)—Deferral of the Effective Date," which deferred the effective date of ASU 2014-09 by one year to December 15, 2017 for annual reporting periods beginning after that date. The FASB also proposed permitting early adoption of the standard, but not before the original effective date of December 15, 2016.

In March 2016, the FASB issued ASU No. 2016-08, "Revenue from Contracts with Customers (Topic 606)—Principal versus Agent Considerations (Reporting Revenue Gross versus Net)". ASU No. 2016-08 requires an entity to determine whether the nature of its promise is to provide the specified good or service itself (i.e., the entity is a principal) or to arrange for that good or service to be provided by the other party (i.e., the entity is an agent) when another party is involved in providing goods or services to a customer. Additionally, the amendments in this ASU require an entity that is a principal to recognize revenue in the gross amount of consideration to which it expects to be entitled in exchange for the specified good or service transferred to the customer, and require an entity that is an agent to recognize revenue in the amount of any fee or commission to which it expects to be entitled in exchange for arranging for the specified good or service to be provided by the other party.

In April 2016, the FASB issued ASU No. 2016-10, “Revenue from Contracts with Customers (Topic 606)—Identifying Performance Obligations and Licensing”. The amendments in ASU No. 2016-10 impact entities with transactions that include contracts with customers to transfer goods or services (that are an output of the entity’s ordinary activities) in exchange for consideration, and they require entities to recognize revenue by following certain steps, including (1) identifying the contract(s) with a customer; (2) identifying the performance obligations in a contract; (3) determining the transaction price; (4) allocating the transaction price to the performance obligations in the contract; and (5) recognizing revenue when, or as, the entity satisfies a performance obligation. Notably, ASU No. 2016-10 does not impact the core revenue recognition principles set forth in Topic 606, but rather clarifies the identification of performance obligations and the licensing implementation guidance, while retaining the related principles for those areas.

Table of Contents

The Partnership is currently evaluating the impact, if any, the adoption of these revenue standards will have on our Condensed Consolidated Financial Statements and related disclosures. In connection with our assessment work, we formed an implementation work team, completed training on the ASU No. 2016-10 revenue recognition model and are continuing our review of contracts with our customers relative to the provisions of these revenue standards.

Leases

In February 2016, the FASB issued ASU 2016-02, “Leases (Topic 842).” This standard requires, among other things, that lessees recognize the following for all leases (with the exception of short-term leases) at the commencement date: (1) a lease liability, which is a lessee’s obligation to make lease payments arising from a lease, measured on a discounted basis; and (2) a right-of-use asset, which is an asset that represents the lessee’s right to use, or control the use of, a specified asset for the lease term. Lessees and lessors must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. The Partnership expects to adopt this standard in the first quarter of 2019 and is currently evaluating the impact of this standard on our Condensed Consolidated Financial Statements and related disclosures. In connection with our assessment work, we formed an implementation work team and are continuing our review of our contracts relative to the provisions of the lease standard.

Share-Based Compensation

In March 2016, the FASB issued ASU No. 2016-09, “Compensation—Stock Compensation (Topic 718).” This standard makes several modifications to Topic 718 related to the accounting for forfeitures, employer tax withholding on share-based compensation and the financial statement presentation of excess tax benefits or deficiencies. ASU 2016-09 also clarifies the statement of cash flows presentation for certain components of share-based awards. The standard is effective for interim and annual reporting periods beginning after December 15, 2016, although early adoption is permitted. The Partnership will adopt the amendment in the fourth quarter of 2016 and has determined the adoption of this standard will not have a material impact on our Condensed Consolidated Financial Statements and related disclosures.

Financial Instruments—Credit Losses

In June 2016, the FASB issued ASU No. 2016-13, “Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments.” This standard requires entities to measure all expected credit losses of financial assets held at a reporting date based on historical experience, current conditions, and reasonable and supportable forecasts in order to record credit losses in a more timely matter. ASU 2016-13 also amends the accounting for credit losses on available-for-sale debt securities and purchased financial assets with credit deterioration. The standard is effective for interim and annual reporting periods beginning after December 15, 2019, although early adoption is permitted for interim and annual periods beginning after December 15, 2018. The Partnership is currently evaluating the impact, if any, the adoption of this standard will have on our Condensed Consolidated Financial Statements and related disclosures.

Statement of Cash Flows

In August 2016, the FASB issued ASU No. 2016-15, “Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments.” This standard is intended to reduce existing diversity in practice in how certain transactions are presented on the statement of cash flows. The standard is effective for interim and annual reporting periods beginning after December 15, 2017, although early adoption is permitted. The Partnership is currently evaluating the impact, if any, the adoption of this standard will have on our Condensed Consolidated Financial Statements and related disclosures.

Table of Contents

(3) Earnings Per Limited Partner Unit

The following table illustrates the Partnership's calculation of earnings per unit for common and subordinated units:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions, except per unit data)			
Net income (loss)	$119	$(991)	$244	$(823)
Net loss attributable to noncontrolling interest	—	(6)	—	(6)
Series A Preferred Unit distribution	9	—	13	—
General partner interest in net income	—	—	—	—
Net income (loss) available to common and subordinated unitholders	$110	$(985)	$231	$(817)
Net income (loss) allocable to common units	$56	$(499)	$117	$(414)
Net income (loss) allocable to subordinated units	54	(486)	114	(403)
Net income (loss) available to common and subordinated unitholders	$110	$(985)	$231	$(817)
Net income (loss) allocable to common units	$56	$(499)	$117	$(414)
Dilutive effect of Series A Preferred Unit distribution	—	—	—	—
Dilutive effect of performance units	—	—	—	—
Diluted net income (loss) allocable to common units	56	(499)	117	(414)
Diluted net income (loss) allocable to subordinated units	54	(486)	114	(403)
Total	$110	$(985)	$231	$(817)
Basic weighted average number of outstanding				
Common units	214	214	214	214
Subordinated units	208	208	208	208
Total	422	422	422	422
Basic earnings (loss) per unit				
Common units	$0.26	$(2.33)	$0.55	$(1.93)
Subordinated units	$0.26	$(2.34)	$0.55	$(1.94)
Basic weighted average number of outstanding common units	214	214	214	214
Dilutive effect of Series A Preferred Units	—	—	—	—
Dilutive effect of performance units	—	—	—	—
Diluted weighted average number of outstanding common units	214	214	214	214
Diluted weighted average number of outstanding subordinated units	208	208	208	208
Total	422	422	422	422
Diluted earnings (loss) per unit				
Common units	$0.26	$(2.33)	$0.55	$(1.93)
Subordinated units	$0.26	$(2.34)	$0.55	$(1.94)

There was no dilutive effect of Series A Preferred Units during the three and nine months ended September 30, 2016 and 2015. The dilutive effect of the unit-based awards discussed in Note 13 was less than $0.01 per unit during the three and nine months ended September 30, 2016 and 2015.

Table of Contents

(4) Partners' Equity

The Partnership Agreement requires that, within 60 days subsequent to the end of each quarter, the Partnership distribute all of its available cash (as defined in the Partnership Agreement) to unitholders of record on the applicable record date.

The Partnership paid or has authorized payment of the following cash distributions to common and subordinated unitholders during 2015 and 2016 (in millions, except for per unit amounts):

Quarter Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
September 30, 2016 (1)	November 14, 2016	November 22, 2016	$ 0.318	$ 134
June 30, 2016	August 16, 2016	August 23, 2016	$ 0.318	$ 134
March 31, 2016	May 6, 2016	May 13, 2016	$ 0.318	$ 134
December 31, 2015	February 2, 2016	February 12, 2016	$ 0.318	$ 134
September 30, 2015	November 3, 2015	November 13, 2015	$ 0.318	$ 134
June 30, 2015	August 3, 2015	August 13, 2015	$ 0.316	$ 134
March 31, 2015	May 5, 2015	May 15, 2015	$ 0.3125	$ 132

(1) The board of directors of Enable GP declared this $0.318 per common unit cash distribution on November 1, 2016, to be paid on November 22, 2016, to common and subordinated unitholders of record at the close of business on November 14, 2016.

The Partnership paid or has authorized payment of the following cash distributions to holders of the Series A Preferred Units during 2016 (in millions, except for per unit amounts):

Quarter Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
September 30, 2016 (1)	November 1, 2016	November 14, 2016	$ 0.625	$ 9
June 30, 2016	August 2, 2016	August 12, 2016	$ 0.625	$ 9
March 31, 2016 (2)	May 6, 2016	May 13, 2016	$ 0.2917	$ 4

(1) The board of directors of Enable GP declared a $0.625 per Series A Preferred Unit cash distribution on November 1, 2016, to be paid on November 14, 2016, to Series A Preferred unitholders of record at the close of business on November 1, 2016.

(2) The prorated quarterly distribution for the Series A Preferred Units is for a partial period beginning on February 18, 2016, and ending on March 31, 2016, which equates to $0.625 per unit on a full-quarter basis or $2.50 per unit on an annualized basis.

General Partner Interest and Incentive Distribution Rights

Enable GP owns a non-economic general partner interest in the Partnership and thus will not be entitled to distributions that the Partnership makes prior to the liquidation of the Partnership in respect of such general partner interest. Enable GP currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50.0%, of the cash the Partnership distributes from operating surplus (as defined in the Partnership Agreement) in excess of $0.330625 per unit per quarter. The maximum distribution of 50.0% does not include any distributions that Enable GP or its affiliates may receive on common units or subordinated units that they own.

Table of Contents

Subordinated Units

Subordinated Unit Ownership

All subordinated units are held by CenterPoint Energy and OGE Energy. These units are considered subordinated because for a period of time, defined by the Partnership Agreement as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received distributions of available cash each quarter from operating surplus in an amount equal to $0.2875 per common unit, which amount is defined in the Partnership Agreement as the minimum quarterly distribution, plus any arrearages on minimum quarterly distributions on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. In addition, during the subordination period, the subordinated units are not entitled to arrearages on minimum quarterly distributions. On the expiration of the subordination period, the subordinated units will convert to common units on a one-for-one basis.

Subordination Period

The subordination period began on the closing date of the Offering and expires on the first business day after the date on which the following tests are met: (1) distributions of available cash from operating surplus (as defined in the Partnership Agreement) on each of the outstanding common units and subordinated units equal or exceed $1.15 per unit (the annualized minimum quarterly distribution) for each of the three consecutive, non-overlapping four-quarter periods immediately preceding June 30, 2017 and (2) the adjusted operating surplus for each of the three consecutive, non-overlapping four-quarter periods immediately preceding such date equaled or exceeded the sum of the minimum quarterly distribution on all common units and subordinated units that were outstanding during such periods on a fully diluted weighted average basis. Also, if the Partnership has paid distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equal to or exceeding $1.725 per unit (150% of the annualized minimum quarterly distribution) and the related distribution on the incentive distribution rights, for any four-consecutive-quarter period ending on or after June 30, 2015, the subordination period will expire.

Series A Preferred Units

On February 18, 2016, the Partnership completed the private placement of 14,520,000 Series A Preferred Units representing limited partner interests in the Partnership for a cash purchase price of $25.00 per Series A Preferred Unit, resulting in proceeds of $362 million, net of issuance costs. The Partnership incurred approximately $1 million of expenses related to the offering, which is shown as an offset to the proceeds. In connection with the closing of the private placement, the Partnership redeemed approximately $363 million of notes scheduled to mature in 2017 payable to a wholly-owned subsidiary of CenterPoint Energy.

Pursuant to the Partnership Agreement, the Series A Preferred Units:

- rank senior to the Partnership’s common units with respect to the payment of distributions and distribution of assets upon liquidation, dissolution and winding up;
- have no stated maturity;
- are not subject to any sinking fund; and
- will remain outstanding indefinitely unless repurchased or redeemed by the Partnership or converted into its common units in connection with a change of control.

Holders of the Series A Preferred Units receive a quarterly cash distribution on a non-cumulative basis if and when declared by the General Partner, and subject to certain adjustments, equal to an annual rate of: 10% on the stated liquidation preference of $25.00 from the date of original issue to, but not including, the five year anniversary of the original issue date; and thereafter a percentage of the stated liquidation preference equal to the sum of the three-month

LIBOR plus 8.5%.

At any time on or after five years after the original issue date, the Partnership may redeem the Series A Preferred Units, in whole or in part, from any source of funds legally available for such purpose, by paying $25.50 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. In addition, the Partnership (or a third-party with its prior written consent) may redeem the Series A Preferred Units following certain changes in the methodology employed by ratings agencies, changes of control or fundamental transactions as set forth in the Partnership Agreement. If, upon a change of control or certain fundamental transactions, the Partnership (or a third-party with its prior written consent) does not exercise this option, then the holders of the Series A Preferred Units have the option to convert the Series A Preferred Units into a number of common units per Series A Preferred Unit as set forth in the Partnership Agreement. The Series

Table of Contents

A Preferred Units are also required to be redeemed in certain circumstances if they are not eligible for trading on the New York Stock Exchange.

Holders of Series A Preferred Units have no voting rights except for limited voting rights with respect to potential amendments to the Partnership Agreement that have a material adverse effect on the existing terms of the Series A Preferred Units, the issuance by the Partnership of certain securities, approval of certain fundamental transactions and as required by law.

Upon the transfer of any Series A Preferred Unit to a non-affiliate of CenterPoint Energy, the Series A Preferred Units will automatically convert into a new series of preferred units (the Series B Preferred Units) on the later of the date of transfer and the second anniversary of the date of issue. The Series B Preferred Units will have the same terms as the Series A Preferred Units except that unpaid distributions on the Series B Preferred Units will accrue on a cumulative basis until paid.

On February 18, 2016, the Partnership entered into a Registration Rights Agreement with CenterPoint Energy, pursuant to which, among other things, the Partnership gave CenterPoint Energy certain rights to require the Partnership to file and maintain a registration statement with respect to the resale of the Series A Preferred Units and any other series of preferred units or common units representing limited partner interests in the Partnership that are issuable upon conversion of the Series A Preferred Units.

(5) Assessing Impairment of Long-lived Assets (including Intangible Assets) and Goodwill

Impairment of Long-lived Assets (including Intangible Assets)

The Partnership periodically evaluates long-lived assets, including property, plant and equipment, and specifically identifiable intangibles other than goodwill, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. During each of the three and nine months ended September 30, 2016, the Partnership recorded an $8 million impairment and during each of the three and nine months ended September 30, 2015, the Partnership recorded a $6 million impairment, to our Service Star business line, which is included in Impairments on the Condensed Consolidated Statements of Income. The Service Star business line is a component of our gathering and processing segment, that provides measurement and communication services to third parties. The 2016 impairment, which impaired substantially all of the remaining net book value of the Service Star business line, was primarily driven by the impact of planned technology changes affecting Service Star and in 2015, the impairment was primarily driven by the expected loss of customers by Service Star. During each of the three and nine months ended September 30, 2015, the Partnership recorded a $12 million impairment on jurisdictional pipelines in our transportation and storage segment. The Partnership recorded no other material impairments to long-lived assets in the three and nine months ended September 30, 2016 and 2015. Based upon review of forecasted undiscounted cash flows, none of the other asset groups were at risk of failing step one of the impairment test. Further price declines, throughput declines, cost increases, regulatory or political environment changes, and other changes in market conditions could reduce forecast undiscounted cash flows.

Impairment of Goodwill

When the Partnership performed its goodwill impairment analysis as of October 1, 2015, the Partnership determined that goodwill was completely impaired in the amount of $1,087 million, which is included in Impairments on the Condensed Consolidated Statements of Income for the three and nine months ended September 30, 2015. As a result, the Partnership did not have any goodwill recorded as of September 30, 2016 or December 31, 2015.

(6) Investment in Equity Method Affiliate

The Partnership uses the equity method of accounting for investments in entities in which it has an ownership interest between 20% and 50% and exercises significant influence.

For the period from December 31, 2014 through June 29, 2015, the Partnership held a 49.90% interest in SESH. On June 12, 2015, CenterPoint Energy exercised its put right with respect to its remaining 0.1% interest in SESH. Pursuant to the put right, on June 30, 2015, CenterPoint Energy contributed a 0.1% interest in SESH to the Partnership in exchange for 25,341 common units representing limited partner interests in the Partnership, which had a fair value of $1 million based upon the closing market price of the Partnership’s common units. Spectra Energy Partners, LP owns the remaining 50% interest in SESH. Pursuant to the terms of the SESH LLC Agreement, if, at any time, CenterPoint Energy has a right to receive less than 50% of our distributions through its interest in the Partnership and its economic interest in Enable GP, or does not have the ability to exercise certain control

Table of Contents

rights, Spectra Energy Partners, LP may, under certain circumstances, have the right to purchase our interest in SESH at fair market value. As of September 30, 2016, the Partnership owned a 50% interest in SESH.

The Partnership shares operations of SESH with Spectra Energy Partners, LP under service agreements. The Partnership is responsible for the field operations of SESH. SESH reimburses each party for actual costs incurred, which are billed based upon a combination of direct charges and allocations. The Partnership billed SESH $3 million and $6 million during the three months ended September 30, 2016 and 2015, respectively, and $12 million and $10 million during the nine months ended September 30, 2016 and 2015, respectively, associated with these service agreements.

Investment in Equity Method Affiliate:

	Nine Months Ended September 30,	
	2016	2015
	(In millions)	
Balance as of December 31,	$344	$348
Interest acquisition of SESH	—	1
Equity in earnings of equity method affiliate	22	21
Contributions to equity method affiliate	—	8
Distributions from equity method affiliate[1]	(40)	(37)
Balance as of September 30,	$326	$341

(1) Distributions from equity method affiliate includes a $22 million and $26 million return on investment and a $18 million and $11 million return of investment for the nine months ended September 30, 2016 and 2015, respectively.

Equity in Earnings of Equity Method Affiliate:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions)			
SESH	$8	$ 7	$ 22	$ 21

Distributions from Equity Method Affiliate:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions)			
SESH	$13	$ 10	$ 40	$ 37

Summarized financial information of SESH:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions)			
Income Statements:				
Revenues	$ 29	$ 29	$ 86	$ 86
Operating income	19	18	56	54
Net income	15	14	43	42

Table of Contents

(7) Debt

The following table presents the Partnership's outstanding debt as of September 30, 2016 and December 31, 2015.

	September 30, 2016	December 31, 2015
	(In millions)	
Commercial Paper	$—	$ 236
2015 Term Loan Agreement	450	450
Revolving Credit Facility	755	310
Notes payable — affiliated companies (Note 11)	—	363
2019 Notes	500	500
2024 Notes	600	600
2044 Notes	550	550
EOIT Senior Notes	250	250
Premium (Discount) on long-term debt	19	23
Total debt	3,124	3,282
Less: Short-term debt[(1)]	—	236
Less: Unamortized debt expense	11	12
Less: Notes payable—affiliated companies	—	363
Total long-term debt	$3,113	$ 2,671

(1) There were no commercial paper borrowings outstanding as of September 30, 2016. Short-term debt included $236 million of commercial paper as of December 31, 2015.

Revolving Credit Facility

On June 18, 2015, the Partnership amended and restated its Revolving Credit Facility to, among other things, increase the borrowing capacity thereunder to $1.75 billion and extend its maturity date to June 18, 2020. As of September 30, 2016, there was $755 million of principal advances and $3 million in letters of credit outstanding under the Revolving Credit Facility. The weighted average interest rate of the Revolving Credit Facility was 2.03% as of September 30, 2016.

The Revolving Credit Facility provides that outstanding borrowings bear interest at LIBOR and/or an alternate base rate, at the Partnership's election, plus an applicable margin. The applicable margin is based on the Partnership's applicable credit ratings. As of September 30, 2016, the applicable margin for LIBOR-based borrowings under the Revolving Credit Facility was 1.50% based on the Partnership's credit ratings. In addition, the Revolving Credit Facility requires the Partnership to pay a fee on unused commitments. The commitment fee is based on the Partnership's applicable credit rating from the rating agencies. As of September 30, 2016, the commitment fee under the Revolving Credit Facility was 0.20% per annum based on the Partnership's credit ratings. The commitment fee is recorded as interest expense in the Partnership's Condensed Consolidated Statements of Income.

Commercial Paper

The Partnership has a commercial paper program, pursuant to which the Partnership is authorized to issue up to $1.4 billion of commercial paper. The commercial paper program is supported by our Revolving Credit Facility, and outstanding commercial paper effectively reduces our borrowing capacity thereunder. There was zero and $236 million outstanding under our commercial paper program as of September 30, 2016 and December 31, 2015, respectively. On February 2, 2016, Standard & Poor's Ratings Services lowered its credit rating on the Partnership from an investment grade rating to a non-investment grade rating. The short-term rating on the Partnership was also reduced from an investment grade rating to a non-investment grade rating. As a result of the downgrade, the Partnership repaid its outstanding borrowings under the commercial program upon maturity and did not issue any additional commercial paper.

Table of Contents

Term Loan Agreement

On July 31, 2015, the Partnership entered into a Term Loan Agreement, providing for an unsecured three-year $450 million term loan agreement (2015 Term Loan Agreement). The entire $450 million principal amount of the 2015 Term Loan Agreement was borrowed by the Partnership on July 31, 2015. The 2015 Term Loan Agreement contains an option, which may be exercised up to two times, to extend the term of the 2015 Term Loan Agreement, in each case, for an additional one-year term. The 2015 Term Loan Agreement provides an option to prepay, without penalty or premium, the amount outstanding, or any portion thereof, in a minimum amount of $1 million, or any multiple of $0.5 million in excess thereof. As of September 30, 2016, there was $450 million outstanding under the 2015 Term Loan Agreement. As of September 30, 2016, the weighted average interest rate of the 2015 Term Loan Agreement was 1.83%.

The 2015 Term Loan Agreement provides that outstanding borrowings bear interest at LIBOR and/or an alternate base rate, at the Partnership's election, plus an applicable margin. The applicable margin is based on our applicable credit ratings. As of September 30, 2016, the applicable margin for LIBOR-based borrowings under the term loan agreement was 1.375% based on the Partnership's credit ratings.

Senior Notes

In connection with the issuance of the 2019 Notes, 2024 Notes and 2044 Notes, the Partnership, CenterPoint Energy Resources Corp., as guarantor of the 2019 Notes and the 2024 Notes, and RBS Securities Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Credit Suisse Securities (USA) LLC, and RBC Capital Markets, LLC, as representatives of the initial purchasers, entered into a registration rights agreement whereby the Partnership and the guarantor agreed to file with the SEC a registration statement relating to a registered offer to exchange the 2019 Notes, 2024 Notes and 2044 Notes for new series of the Partnership's notes in the same aggregate principal amount as, and with terms substantially identical in all respects to, the 2019 Notes, 2024 Notes and 2044 Notes. On December 29, 2015, the Partnership completed the exchange offer.

A wholly owned subsidiary of CenterPoint Energy guaranteed collection of the Partnership's obligations under the 2019 Notes and the 2024 Notes, which expired on May 1, 2016.

As of September 30, 2016, the Partnership's debt included EOIT's $250 million 6.25% senior notes due March 2020 (the EOIT Senior Notes). The EOIT Senior Notes have a $20 million unamortized premium at September 30, 2016, resulting in an effective interest rate of 5.80%, during the nine months ended September 30, 2016. These senior notes do not contain any financial covenants other than a limitation on liens. This limitation on liens is subject to certain exceptions and qualifications.

Financing Costs

Unamortized debt expense of $16 million and $18 million as of September 30, 2016 and December 31, 2015, respectively, is classified as either a reduction to Long-Term Debt or Other Assets in the Condensed Consolidated Balance Sheets and is being amortized over the life of the respective debt. Unamortized premium, net of unamortized discount on long-term debt of $19 million and $23 million at September 30, 2016 and December 31, 2015, respectively, is classified as either Long-Term Debt or Short-Term Debt, consistent with the underlying debt instrument, in the Condensed Consolidated Balance Sheets and is being amortized over the life of the respective debt.

As of September 30, 2016, the Partnership and EOIT were in compliance with all of their debt agreements, including financial covenants.

(8) Fair Value Measurements

Certain assets and liabilities are recorded at fair value in the Condensed Consolidated Balance Sheets and are categorized based upon the level of judgment associated with the inputs used to measure their value. Hierarchical levels, as defined below and directly related to the amount of subjectivity associated with the inputs to fair valuations of these assets and liabilities are as follows:

Level 1: Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date. Instruments classified as Level 1 include natural gas futures, swaps and options transactions for contracts traded on the NYMEX and settled through a NYMEX clearing broker.

Level 2: Inputs, other than quoted prices included in Level 1, are observable for the asset or liability, either directly or indirectly. Level 2 inputs include quoted prices for similar instruments in active markets, and inputs other than quoted prices that are observable for the asset or liability. Fair value assets and liabilities that are generally included in this category are derivatives with fair values based on inputs from actively quoted markets. Instruments classified as Level 2 include over-the-counter NYMEX natural gas swaps, natural gas basis swaps and natural gas purchase and sales transactions in markets such that the pricing is closely related to the NYMEX pricing, and over-the-counter WTI crude swaps for condensate sales.

Level 3: Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability. Unobservable inputs reflect the Partnership's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Partnership develops these inputs based on the best information available, including the Partnership's own data.

The Partnership utilizes the market approach in determining the fair value of its derivative positions by using either NYMEX or WTI published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX published market prices may be considered Level 1 if they are settled through a NYMEX clearing broker account with daily margining. Over-the-counter derivatives with NYMEX or WTI based prices are considered Level 2 due to the impact of counterparty credit risk. Valuations based on independent broker pricing or broker/dealer valuations may be classified as Level 2 only to the extent they may be validated by an additional source of independent market data for an identical or closely related active market. In certain less liquid markets or for longer-term contracts, forward prices are not as readily available. In these circumstances, contracts are valued using internally developed methodologies that consider historical relationships among various quoted prices in active markets that result in management's best estimate of fair value. These contracts are classified as Level 3.

The Partnership determines the appropriate level for each financial asset and liability on a quarterly basis and recognizes transfers between levels at the end of the reporting period. For the period ended September 30, 2016, there were no transfers between Level 1, 2, and 3 investments.

The impact to the fair value of derivatives due to credit risk is calculated using the probability of default based on Standard & Poor's Ratings Services and/or internally generated ratings. The fair value of derivative assets is adjusted for credit risk. The fair value of derivative liabilities is adjusted for credit risk only if the impact is deemed material.

Contracts with Master Netting Arrangements

Fair value amounts recognized for forward, interest rate swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Condensed Consolidated Balance Sheets. The Partnership has presented the fair values of its derivative contracts under master netting agreements using a net fair value presentation.

The following tables summarize the Partnership's assets and liabilities that are measured at fair value on a recurring basis as of September 30, 2016 and December 31, 2015:

September 30, 2016	Commodity Contracts	Gas Imbalances (1)

	Assets	Liabilities	Assets (2)	Liabilities (3)
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$2	$ 9	$ —	$ —
Significant other observable inputs (Level 2)	1	1	17	16
Unobservable inputs (Level 3)	—	5	—	—
Total fair value	3	15	17	16
Netting adjustments	(1)	(1)	—	—
Total	$2	$ 14	$ 17	$ 16

December 31, 2015	Commodity Contracts		Gas Imbalances (1)	
	Assets	Liabilities	Assets (2)	Liabilities (3)
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$17	$ 3	$ —	$ —
Significant other observable inputs (Level 2)	10	—	17	20
Unobservable inputs (Level 3)	4	—	—	—
Total fair value	31	3	17	20
Netting adjustments	(3)	(3)	—	—
Total	$28	$ —	$ 17	$ 20

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(1) The Partnership uses the market approach to fair value its gas imbalance assets and liabilities at individual, or where appropriate an average of, current market indices applicable to the Partnership's operations, not to exceed net realizable value. Gas imbalances held by EOIT are valued using an average of the Inside FERC Gas Market Report for Panhandle Eastern Pipe Line Co. (Texas, Oklahoma Mainline), ONEOK (Oklahoma) and ANR Pipeline (Oklahoma) indices. There were no netting adjustments as of September 30, 2016 and December 31, 2015.

(2) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of $3 million and $6 million at September 30, 2016 and December 31, 2015, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

(3) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of $6 million and $5 million at September 30, 2016 and December 31, 2015, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

Changes in Level 3 Fair Value Measurements

The following table provides a reconciliation of changes in the fair value of our Level 3 commodity contracts between the periods presented.

	Commodity Contracts Natural gas liquids financial futures/swaps
	(In millions)
Balance as of December 31, 2015	$ 4
Losses included in earnings	(8)
Settlements	(1)
Balance as of September 30, 2016	$ (5)

Quantitative Information on Level 3 Fair Value Measurements

The Partnership utilizes the market approach to measure the fair value of our commodity contracts. The significant unobservable inputs used in this approach to fair value are longer dated price quotes. Our sensitivity to these longer dated forward curve prices are presented in the table below. Significant changes in any of those inputs in isolation would result in significantly different fair value measurements, depending on our short or long position in contracts.

Product Group	September 30, 2016	
	Fair Value	Forward Curve Range

	(In millions)	(Per gallon)
Natural gas liquids	$5	$0.530 - $0.568

Estimated Fair Value of Financial Instruments

The fair values of all accounts receivable, notes receivable, accounts payable, commercial paper, and other such financial instruments on the Condensed Consolidated Balance Sheets are estimated to be approximately equivalent to their carrying amounts and have been excluded from the table below. The following table summarizes the fair value and carrying amount of the Partnership’s financial instruments as of September 30, 2016 and December 31, 2015.

	September 30, 2016		December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-Term Debt				
Long-term notes payable—affiliated companies (Level 2)	$ —	$ —	$ 363	$ 350
Revolving Credit Facility (Level 2)[1]	755	755	310	310
2015 Term Loan Agreement (Level 2)	450	450	450	450
EOIT Senior Notes (Level 2)	270	268	273	280
Enable Midstream Partners, LP 2019, 2024 and 2044 Notes (Level 2)	1,649	1,525	1,650	1,255

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(1) Borrowing capacity is effectively reduced by our borrowings outstanding under the commercial paper program. There was zero and $236 million of commercial paper outstanding as of September 30, 2016 and December 31, 2015, respectively.

The fair value of the Partnership’s Long-term notes payable—affiliated companies, Revolving Credit Facility, and 2015 Term Loan Agreement, along with the EOIT Senior Notes and Enable Midstream Partners, LP 2019, 2024 and 2044 Notes, is based on quoted market prices and estimates of current rates available for similar issues with similar maturities and is classified as Level 2 in the fair value hierarchy.

Non-Financial Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis; that is, the assets and liabilities are not measured at fair value on an ongoing basis, but are subject to fair value adjustments in certain circumstances (e.g., when there is evidence of impairment).

As of September 30, 2016, no other material fair value adjustments or fair value measurements were required for these non-financial assets or liabilities, with the exception of those discussed in Note 5.

(9) Derivative Instruments and Hedging Activities

The Partnership is exposed to certain risks relating to its ongoing business operations. The primary risk managed using derivative instruments is commodity price risk. The Partnership is also exposed to credit risk in its business operations.

Commodity Price Risk

The Partnership has used forward physical contracts, commodity price swap contracts and commodity price option features to manage the Partnership’s commodity price risk exposures in the past. Commodity derivative instruments used by the Partnership are as follows:

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NGL put options, NGL futures and swaps, and WTI crude oil futures and swaps for condensate sales are used to manage the Partnership's NGL and condensate exposure associated with its processing agreements and asset management activities;

- natural gas futures and swaps are used to manage the Partnership's natural gas exposure associated with its gathering, processing and transportation and storage assets; and
- natural gas futures and swaps, natural gas options and natural gas commodity purchases and sales are used to manage the Partnership's natural gas exposure associated with its storage and transportation contracts and asset management activities.

Table of Contents

Normal purchases and normal sales contracts are not recorded in Other Assets or Liabilities in the Condensed Consolidated Balance Sheets and earnings are recognized and recorded in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales treatment to: (i) commodity contracts for the purchase and sale of natural gas used in or produced by the Partnership's operations and (ii) commodity contracts for the purchase and sale of NGLs produced by the Partnership's gathering and processing business.

The Partnership recognizes its non-exchange traded derivative instruments as Other Assets or Liabilities in the Condensed Consolidated Balance Sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. Exchange traded transactions are settled on a net basis daily through margin accounts with a clearing broker and, therefore, are recorded at fair value on a net basis in Other Current Assets in the Condensed Consolidated Balance Sheets.

As of September 30, 2016 and December 31, 2015, the Partnership had no derivative instruments that were designated as cash flow or fair value hedges for accounting purposes.

Credit Risk

The Partnership is exposed to certain credit risks relating to its ongoing business operations. Credit risk includes the risk that counterparties that owe the Partnership money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, the Partnership may be forced to enter into alternative arrangements. In that event, the Partnership's financial results could be adversely affected, and the Partnership could incur losses.

Derivatives Not Designated As Hedging Instruments

Derivative instruments not designated as hedging instruments for accounting purposes are utilized in the Partnership's asset management activities. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized currently in earnings.

Quantitative Disclosures Related to Derivative Instruments

The majority of natural gas physical purchases and sales not designated as hedges for accounting purposes are priced based on a monthly or daily index, and the fair value is subject to little or no market price risk. Natural gas physical sales volumes exceed natural gas physical purchase volumes due to the marketing of natural gas volumes purchased via the Partnership's processing contracts, which are not derivative instruments.

As of September 30, 2016 and December 31, 2015, the Partnership had the following derivative instruments that were not designated as hedging instruments for accounting purposes:

	September 30, 2016		December 31, 2015	
	Gross Notional Volume			
	Purchases	Sales	Purchases	Sales
Natural gas—TBtu[1]				
Financial fixed futures/swaps	2	34	1	37
Financial basis futures/swaps	2	34	4	38
Physical purchases/sales	—	39	2	51
Crude oil (for condensate)—MBbl[2]				

Financial Futures/swaps	—	450	—	506
Natural gas liquids—MBbl[3]				
Financial Futures/swaps	75	1,248	75	1,011

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(1) As of September 30, 2016, 94.0% of the natural gas contracts had durations of one year or less and 6.0% had durations of more than one year and less than two years. As of December 31, 2015, 97.7% of the natural gas contracts had durations of one year or less and 2.3% had durations of more than one year and less than two years.

(2) As of September 30, 2016, 90.0% of the condensate contracts had durations of one year or less and 10.0% had durations of more than one year and less than two years. As of December 31, 2015, 100% of the crude oil (for condensate) contracts had durations of one year or less.

Table of Contents

(3) As of September 30, 2016, 89.8% of the natural gas liquids contracts had durations of one year or less and 10.2% had durations of more than one year and less than two years. As of December 31, 2015, 100% of the natural gas liquid contracts had durations of one year or less.

Balance Sheet Presentation Related to Derivative Instruments

The fair value of the derivative instruments that are presented in the Partnership's Condensed Consolidated Balance Sheets as of September 30, 2016 and December 31, 2015 that were not designated as hedging instruments for accounting purposes are as follows:

		September 30, 2016		December 31, 2015	
		Fair Value			
Instrument	Balance Sheet Location	Assets	Liabilities	Assets	Liabilities
		(In millions)			
Natural gas					
Financial futures/swaps	Other Current	$2	$ 9	$ 17	$ 3
Physical purchases/sales	Other Current	—	—	1	—
Crude Oil (for condensate)					
Financial futures/swaps	Other Current	1	1	9	—
Natural gas liquids					
Financial Futures/swaps	Other Current	—	5	4	—
Total gross derivatives [1]		$3	$ 15	$ 31	$ 3

(1) See Note 8 for a reconciliation of the Partnership's total derivatives fair value to the Partnership's Condensed Consolidated Balance Sheets as of September 30, 2016 and December 31, 2015.

Income Statement Presentation Related to Derivative Instruments

The following table presents the effect of derivative instruments on the Partnership's Condensed Consolidated Statements of Income for the three and nine months ended September 30, 2016 and 2015.

	Amounts Recognized in Income			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions)			
Natural gas financial futures/swaps gains (losses)	$6	$10	$(5)	$13
Natural gas physical purchases/sales gains (losses)	1	(1)	(7)	(5)
Crude Oil (for condensate) financial futures/swaps gains (losses)	1	11	(2)	8
Natural gas liquids financial futures/swaps gains (losses)	1	1	(8)	7
Total	$9	$21	$(22)	$23

For derivatives not designated as hedges in the tables above, amounts recognized in income for the periods ended September 30, 2016 and 2015, if any, are reported in Product Sales.

23

Table of Contents

The following table presents the components of gain (loss) on derivative activity in the Partnership's Condensed Consolidated Statements of Income for the three and nine months ended September 30, 2016 and 2015.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions)			
Change in fair value of derivatives	$8	$ 6	$(40)	$(11)
Realized gain on derivatives	1	15	18	34
Gain (loss) on derivative activity	$9	$ 21	$(22)	$23

Credit-Risk Related Contingent Features in Derivative Instruments

Based upon the Partnership's senior unsecured debt rating with Moody's Investors Services or Standard & Poor's Ratings Services, the Partnership could be required to provide credit assurances to third parties, which could include letters of credit or cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position. As of September 30, 2016, under these obligations, no cash collateral has been posted. However, based on positions as of September 30, 2016, approximately $2 million of additional collateral may be required to be posted by the Partnership.

(10) Supplemental Disclosure of Cash Flow Information

The following table provides information regarding supplemental cash flow information:

	Nine Months Ended September 30,	
	2016	2015
	(In millions)	
Supplemental Disclosure of Cash Flow Information:		
Cash Payments:		
Interest, net of capitalized interest	$ 67	$ 61
Income taxes, net of refunds	1	2
Non-cash transactions:		
Accounts payable related to capital expenditures	32	66
Issuance of common units upon interest acquisition of SESH (Note 6)	—	1

(11) Related Party Transactions

The material related party transactions with CenterPoint Energy, OGE Energy and their respective subsidiaries are summarized below. There were no material related party transactions with other affiliates.

Table of Contents

The Partnership's revenues from affiliated companies accounted for 6% and 6% of revenues during the three months ended September 30, 2016 and 2015, respectively, and 7% and 7% of revenues during the nine months ended September 30, 2016 and 2015, respectively. Amounts of revenues from affiliated companies included in the Partnership's Condensed Consolidated Statements of Income are summarized as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions)			
Gas transportation and storage service revenue — CenterPoint Energy	$22	$ 23	$79	$79
Natural gas product sales — CenterPoint Energy	—	—	1	7
Gas transportation and storage service revenue — OGE Energy	10	10	28	28
Natural gas product sales — OGE Energy	4	3	10	7
Total revenues — affiliated companies	$36	$ 36	$118	$121

Amounts of natural gas purchased from affiliated companies included in the Partnership's Condensed Consolidated Statements of Income are summarized as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions)			
Cost of natural gas purchases — CenterPoint Energy	$—	$ 1	$ —	$ 2
Cost of natural gas purchases — OGE Energy	4	5	9	12
Total cost of natural gas purchases — affiliated companies	$4	$ 6	$ 9	$ 14

Prior to May 1, 2013, the Partnership had employees and reflected the associated benefit costs directly and not as corporate services. Under the terms of the MFA, effective May 1, 2013 the Partnership's employees were seconded by CenterPoint Energy and OGE Energy, and the Partnership began reimbursing each of CenterPoint Energy and OGE Energy for all employee costs under the seconding agreements until the seconded employees transition from CenterPoint Energy and OGE Energy to the Partnership. The Partnership transitioned seconded employees from CenterPoint Energy and OGE Energy to the Partnership effective January 1, 2015, except for certain employees who are participants under OGE Energy's defined benefit and retiree medical plans, who will remain seconded to the Partnership, subject to certain termination rights of the Partnership and OGE Energy. The Partnership's reimbursement of OGE Energy for employee costs arising out of OGE Energy's defined benefit and retiree medical plans is fixed at $6 million in 2016, $5 million in 2017, and at actual cost subject to a cap of $5 million in 2018 and thereafter, in the event of continued secondment.

Prior to May 1, 2013, the Partnership received certain services and support functions from CenterPoint Energy described below. Under the terms of the MFA, effective May 1, 2013, the Partnership receives services and support functions from each of CenterPoint Energy and OGE Energy under service agreements for an initial term that ended on April 30, 2016. The service agreements automatically extend year-to-year at the end of the initial term, unless terminated by the Partnership with at least 90 days' notice prior to the end of any extension. Additionally, the

Partnership may terminate these service agreements at any time with 180 days' notice, if approved by the Board of Enable GP. The Partnership reimburses CenterPoint Energy and OGE Energy for these services up to annual caps, which for 2016 are $7 million and $6 million, respectively.

Amounts charged to the Partnership by affiliates for seconded employees and corporate services, included primarily in Operation and maintenance and General and administrative expenses in the Partnership's Condensed Consolidated Statements of Income are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions)			
Corporate Services — CenterPoint Energy	$ 1	$ 5	$ 6	$ 12
Seconded Employee Costs — OGE Energy	5	12	22	30
Corporate Services — OGE Energy	1	2	4	8
Total corporate services and seconded employees expense	$ 7	$ 19	$ 32	$ 50

The Partnership had outstanding long-term notes payable—affiliated companies to CenterPoint Energy at December 31, 2015 of $363 million, which were scheduled to mature in 2017. On February 18, 2016, in connection with the private placement of the Series A Preferred Units, the Partnership redeemed the $363 million of notes payable—affiliated companies payable to a subsidiary of CenterPoint Energy.

The Partnership recorded affiliated interest expense to CenterPoint Energy on notes payable—affiliated companies of zero and $2 million during the three months ended September 30, 2016 and 2015, respectively, and $1 million and $6 million during the nine months ended September 30, 2016 and 2015, respectively.

On February 18, 2016, the Partnership completed the private placement, with CenterPoint Energy, of 14,520,000 Series A Preferred Units representing limited partner interests in the Partnership for a cash purchase price of $25.00 per Series A Preferred Unit, resulting in proceeds of $362 million, net of issuance costs. See Note 4 for further discussion.

(12) Commitments and Contingencies

The Partnership is involved in legal, environmental, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business. Some of these proceedings involve substantial amounts. The Partnership regularly analyzes current information and, as necessary, provides accruals for probable liabilities on the eventual disposition of these matters. The Partnership does not expect the disposition of these matters to have a material adverse effect on its financial condition, results of operations or cash flows.

(13) Equity Based Compensation

The following table summarizes the Partnership's compensation expense for the three and nine months ended September 30, 2016 and 2015 related to performance units, restricted units, and phantom units for the Partnership's employees and independent directors:

	Three Months	Nine Months

	Ended September 30,		Ended September 30,	
	2016	2015	2016	2015
	(In millions)			
Performance units	$4	$ 1	$ 7	$ 3
Restricted units	1	2	2	5
Phantom units	—	—	1	1
Total compensation expense	$5	$ 3	$ 10	$ 9

Table of Contents

Units Outstanding

The Partnership periodically grants performance units, restricted units, and phantom units to certain employees under the Enable Midstream Partners, LP Long Term Incentive Plan. A summary of the activity for the Partnership's performance units, restricted units, and phantom units applicable to the Partnership's employees at September 30, 2016 and changes during 2016 are shown in the following table.

	Performance Units		Restricted Units		Phantom Units	
	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit
	(In millions, except unit data)					
Units Outstanding at December 31, 2015	814,510	$ 20.67	581,772	$ 21.04	9,817	$ 12.70
Granted	1,235,409	12.80	—	—	647,356	8.39
Vested	(6,427)	20.77	(91,720)	20.84	(321)	8.12
Forfeited	(56,641)	17.27	(53,915)	15.29	(8,421)	18.12
Units Outstanding at September 30, 2016	1,986,841	$ 15.24	436,137	$ 20.89	648,431	$ 8.46
Aggregate Intrinsic Value of Units Outstanding at September 30, 2016	$ 30		$ 7		$ 10	

Unrecognized Compensation Cost

A summary of the Partnership's unrecognized compensation cost for its non-vested performance units, restricted units, and phantom units, and the weighted-average periods over which the compensation cost is expected to be recognized are shown in the following table.

	September 30, 2016	
	Unrecognized Compensation Cost (In millions)	Weighted Average to be Recognized (In years)
Performance Units	$ 17	2.06
Restricted Units	3	1.32
Phantom Units	5	2.44
Total	$ 25	

As of September 30, 2016, there were 9,292,500 units available for issuance under the long term incentive plan.

(14) Reportable Segments

The Partnership's determination of reportable segments considers the strategic operating units under which it manages sales, allocates resources and assesses performance of various products and services to customers in differing regulatory environments. The accounting policies of the reportable segments are the same as those described in the summary of significant accounting policies excerpt in the Partnership's audited 2015 combined and consolidated financial statements included in the Annual Report. The Partnership uses operating income as the measure of profit or loss for its reportable segments.

The Partnership's assets and operations are organized into two reportable segments: (i) Gathering and Processing, which primarily provides natural gas gathering, processing and fractionation services and crude oil gathering for our producer customers, and (ii) Transportation and Storage, which provides interstate and intrastate natural gas pipeline transportation and storage service primarily to natural gas producers, utilities and industrial customers.

Table of Contents

Financial data for reportable segments are as follows:

Three Months Ended September 30, 2016	Gathering and Processing	Transportation and Storage[1]	Eliminations	Total
	(In millions)			
Product sales	$295	$ 150	$ (119)	$326
Service revenue	160	135	(1)	294
Total Revenues	455	285	(120)	620
Cost of natural gas and natural gas liquids	246	141	(119)	268
Operation and maintenance, General and administrative	63	46	(1)	108
Depreciation and amortization	53	31	—	84
Impairments	8	—	—	8
Taxes other than income tax	8	5	—	13
Operating income	$77	$ 62	$ —	$139
Total assets	$7,502	$ 4,947	$ (1,208)	$11,241
Capital expenditures	$52	$ 16	$ —	$68

Three Months Ended September 30, 2015	Gathering and Processing	Transportation and Storage[1]	Eliminations	Total
	(In millions)			
Product sales	$299	$ 166	$ (108)	$357
Service revenue	157	133	(1)	289
Total Revenues	456	299	(109)	646
Cost of natural gas and natural gas liquids	235	161	(109)	287
Operation and maintenance, General and administrative	75	55	—	130
Depreciation and amortization	53	31	—	84
Impairments	514	591	—	1,105
Taxes other than income tax	8	7	—	15
Operating income (loss)	$(429)	$ (546)	$ —	$(975)
Total assets as of December 31, 2015	$7,536	$ 4,976	$ (1,286)	$11,226
Capital expenditures	$167	$ 31	$ —	$198

Table of Contents

Nine Months Ended September 30, 2016	Gathering and Processing	Transportation and Storage[(1)]	Eliminations	Total
	(In millions)			
Product sales	$759	$ 348	$ (270)	$837
Service revenue	416	408	(3)	821
Total Revenues	1,175	756	(273)	1,658
Cost of natural gas and natural gas liquids	642	346	(271)	717
Operation and maintenance, General and administrative	205	140	(2)	343
Depreciation and amortization	154	94	—	248
Impairments	8	—	—	8
Taxes other than income tax	24	19	—	43
Operating income	$142	$ 157	$ —	$299
Total assets	$7,502	$ 4,947	$ (1,208)	$11,241
Capital expenditures	$252	$ 37	$ —	$289

Nine Months Ended September 30, 2015	Gathering and Processing	Transportation and Storage[(1)]	Eliminations	Total
	(In millions)			
Product sales	$875	$ 467	$ (299)	$1,043
Service revenue	404	408	(3)	809
Total Revenues	1,279	875	(302)	1,852
Cost of natural gas and natural gas liquids	698	459	(301)	856
Operation and maintenance, General and administrative	229	163	(1)	391
Depreciation and amortization	141	92	—	233
Impairments	514	591	—	1,105
Taxes other than income tax	23	22	—	45
Operating income (loss)	$(326)	$ (452)	$ —	$(778)
Total assets as of December 31, 2015	$7,536	$ 4,976	$ (1,286)	$11,226
Capital expenditures	$657	$ 77	$ —	$734

(1) See Note 6 for discussion regarding ownership interests in SESH and related equity earnings included in the Transportation and Storage segment for the three and nine months ended September 30, 2016 and 2015.

Table of Contents

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with our unaudited condensed consolidated financial statements and the related notes included herein and our audited combined and consolidated financial statements for the year ended December 31, 2015, included in our Annual Report. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Please read “Forward-Looking Statements.” In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

Overview

We are a large-scale, growth-oriented publicly traded Delaware limited partnership formed to own, operate and develop strategically located natural gas and crude oil infrastructure assets. We serve current and emerging production areas in the United States, including several unconventional shale resource plays and local and regional end-user markets in the United States. Our assets and operations are organized into two reportable segments: (i) Gathering and Processing, which primarily provides natural gas gathering, processing and fractionation services and crude oil gathering for our producer customers, and (ii) Transportation and Storage, which provides interstate and intrastate natural gas pipeline transportation and storage services primarily to natural gas producers, utilities and industrial customers.

Our natural gas gathering and processing assets are located in Oklahoma, Texas, Arkansas, Louisiana and Mississippi and serve natural gas production in the Anadarko, Arkoma and Ark-La-Tex basins. We also own a crude oil gathering business located in North Dakota to serve shale development in the Bakken Shale formation of the Williston Basin. Our natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

We expect our business to continue to be affected by the key trends included in our Annual Report. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about, or interpretations of, available information prove to be incorrect, our actual results may vary materially from our expected results.

How We Evaluate Our Operations

Gross Margin

We use gross margin as a performance measure to analyze the aggregate core profitability of our customer arrangements. We define gross margin as total revenues minus costs of natural gas and natural gas liquids, excluding depreciation and amortization. Total revenues consist of the fees that we charge our customers and the sales price of natural gas and natural liquids that we sell. The cost of natural gas and natural gas liquids consists of the purchase price of natural gas and natural gas liquids that we purchase. We deduct the cost of natural gas and natural gas liquids from total revenue to arrive at a measure of the core profitability of our mix of fee-based and commodity-based customer arrangements. Please read “—Results of Operations” and “—Non-GAAP Financial Measures” below.

The following table shows the components of our gross margin for the nine months ended September 30, 2016:

	Fee-Based			
	Demand	Volume	Commodity-	Total

	Commitment/ Guaranteed Return	Dependent	Based	
Nine Months Ended September 30, 2016				
Gathering and Processing Segment	37 %	42 %	21 %	100 %
Transportation and Storage Segment	91 %	5 %	4 %	100 %
Partnership Weighted Average	60 %	26 %	14 %	100 %

Table of Contents

Recent Developments

Construction update

The Bradley II Plant, a 200 MMcf/d cryogenic processing facility located in Grady County, Oklahoma, was placed in service in the second quarter of 2016 and began full commercial operations in July 2016. We constructed the Bradley II plant to serve producers in the Anadarko basin, and the plant is connected to our super-header processing system.

During the quarter ended June 30, 2016, we elected to delay the scheduled completion of the Wildhorse Plant, on which construction began in the third quarter of 2015. As of September 30, 2016, we have incurred total costs of approximately $115 million in connection with the engineering, site preparation and the purchase and delivery of equipment for the plant. We anticipate that we will complete the construction of the plant once the plant's capacity is necessary to accommodate anticipated volume increases. We expect that the plant will be in service no sooner than the fourth quarter of 2017.

Distribution Reinvestment Program

In June 2016, the Partnership implemented a Distribution Reinvestment Plan (DRIP), which, beginning with the quarterly distribution for the quarter ended September 30, 2016, offers owners of our common and subordinated units the ability to purchase additional common units by reinvesting all or a portion of the cash distributions paid to them on their common or subordinated units. The Partnership will have the sole discretion to determine whether common units purchased under the DRIP will come from our newly issued common units or from common units purchased on the open market. The purchase price for newly issued common units will be the average of the high and low trading prices of the common units on the New York Stock Exchange-Composite Transactions for the five trading days immediately preceding the investment date. The purchase price for common units purchased on the open market will be the weighted average price of all common units purchased for the DRIP for the respective investment date. We can set a discount ranging from 0% to 5% for common units purchased pursuant to the DRIP. The discount is currently set at 0%. Participation in the DRIP is voluntary, and once enrolled, our unitholders may terminate participation at any time.

Results of Operations

The following tables summarize the key components of our results of operations for the three and nine months ended September 30, 2016 and 2015.

Three Months Ended September 30, 2016	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$295	$ 150	$ (119)	$ 326
Service revenue	160	135	(1)	294
Total Revenues	455	285	(120)	620
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	246	141	(119)	268
Gross margin [1]	209	144	(1)	352
Operation and maintenance, General and administrative	63	46	(1)	108
Depreciation and amortization	53	31	—	84
Impairments	8	—	—	8

Taxes other than income tax	8	5	—	13
Operating income	$77	$ 62	$ —	$ 139
Equity in earnings of equity method affiliate	$—	$ 8	$ —	$ 8

31

Table of Contents

Three Months Ended September 30, 2015	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$299	$ 166	$ (108)	$ 357
Service revenue	157	133	(1)	289
Total Revenues	456	299	(109)	646
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	235	161	(109)	287
Gross margin [(1)]	221	138	—	359
Operation and maintenance, General and administrative	75	55	—	130
Depreciation and amortization	53	31	—	84
Impairments	514	591	—	1,105
Taxes other than income tax	8	7	—	15
Operating income (loss)	$(429)	$ (546)	$ —	$ (975)
Equity in earnings of equity method affiliate	$—	$ 7	$ —	$ 7

Nine Months Ended September 30, 2016	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$759	$ 348	$ (270)	$ 837
Service revenue	416	408	(3)	821
Total Revenues	1,175	756	(273)	1,658
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	642	346	(271)	717
Gross margin [(1)]	533	410	(2)	941
Operation and maintenance, General and administrative	205	140	(2)	343
Depreciation and amortization	154	94	—	248
Impairments	8	—	—	8
Taxes other than income tax	24	19	—	43
Operating income	$142	$ 157	$ —	$ 299
Equity in earnings of equity method affiliate	$—	$ 22	$ —	$ 22

Table of Contents

Nine Months Ended September 30, 2015	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Product sales	$875	$ 467	$ (299)	$ 1,043
Service revenue	404	408	(3)	809
Total Revenues	1,279	875	(302)	1,852
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	698	459	(301)	856
Gross margin [1]	581	416	(1)	996
Operation and maintenance, General and administrative	229	163	(1)	391
Depreciation and amortization	141	92	—	233
Impairments	514	591	—	1,105
Taxes other than income tax	23	22	—	45
Operating income (loss)	$(326)	$ (452)	$ —	$ (778)
Equity in earnings of equity method affiliate	$—	$ 21	$ —	$ 21

(1) Gross margin is a non-GAAP measure and is defined and reconciled to its most directly comparable financial measures calculated and presented below under the caption Non-GAAP Financial Measures.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Operating Data:				
Gathered volumes—TBtu	291	291	851	866
Gathered volumes—TBtu/d	3.16	3.17	3.11	3.17
Natural gas processed volumes—TBtu	164	172	487	488
Natural gas processed volumes—TBtu/d	1.78	1.87	1.78	1.79
NGLs produced—MBbl/d [1]	77.53	83.80	78.08	73.81
NGLs sold—MBbl/d [1][2]	73.45	81.63	77.93	74.45
Condensate sold—MBbl/d	4.11	4.63	5.54	5.34
Crude Oil - Gathered volumes—MBbl/d	23.78	16.46	26.03	10.76
Transported volumes—TBtu	441	425	1,352	1,395
Transportation volumes—TBtu/d	4.79	4.62	4.92	5.10
Interstate firm contracted capacity—Bcf/d	6.89	6.71	7.00	7.25
Intrastate average deliveries—TBtu/d	1.77	1.88	1.72	1.85

Table of Contents

	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
Anadarko				
Gathered volumes—TBtu/d	1.66	1.70	1.64	1.59
Natural gas processed volumes—TBtu/d	1.50	1.49	1.45	1.38
NGLs produced—MBbl/d (1)	65.24	70.02	64.53	58.74
Arkoma				
Gathered volumes—TBtu/d	0.61	0.65	0.63	0.68
Natural gas processed volumes—TBtu/d	0.10	0.09	0.10	0.10
NGLs produced—MBbl/d (1)	4.69	4.73	4.90	5.02
Ark-La-Tex				
Gathered volumes—TBtu/d	0.89	0.82	0.84	0.90
Natural gas processed volumes—TBtu/d	0.18	0.29	0.23	0.31
NGLs produced—MBbl/d (1)	7.60	9.05	8.65	10.05

(1) Excludes condensate.
(2) NGLs sold includes volumes of NGLs withdrawn from inventory or purchased for system balancing purposes.

Gathering and Processing

Three Months Ended September 30, 2016 compared to three months ended September 30, 2015. Our gathering and processing segment reported operating income of $77 million in the three months ended September 30, 2016 compared to an operating loss of $429 million in the three months ended September 30, 2015. The difference of $506 million in operating income between periods was primarily due to $514 million of impairments recognized in the third quarter of 2015 related to goodwill and long-lived assets, compared to $8 million of impairments recognized in the third quarter of 2016 related to long-lived assets. In addition, there was a $12 million decrease in operation and maintenance and general and administrative expenses, offset by a $12 million decrease in gross margin during the three months ended September 30, 2016.

Our gathering and processing segment revenues decreased $1 million. The decrease was primarily due to a $10 million reduction in revenues from sales of natural gas as a result of lower average natural gas prices, $7 million in changes in the fair value of condensate and NGL derivatives and a $1 million decrease in revenues on third party measurement and communication services during the third quarter of 2016 as well as one-time project reimbursements of $8 million recognized in the third quarter of 2015. These decreases were partially offset by a $14 million increase in revenues from sales of NGLs as a result of higher average NGL prices, a $9 million increase in natural gas gathering revenues due to higher gathering fees in the Anadarko basin and increased billings under minimum volume commitments and a $3 million increase in crude oil gathering revenues due to higher gathered volumes in the Williston basin.

Our gathering and processing segment gross margin decreased $12 million. The decrease was primarily due to $7 million in changes to the fair value of condensate and NGL derivatives and a $3 million decrease in processing margins resulting from lower NGL volumes sold in the Anadarko and Ark-La-Tex basins, which were partially offset by higher average NGL prices, a $3 million decrease in natural gas gathering margins due to lower average natural gas prices, and a $1 million decrease in revenues on third party measurement and communication services during the third quarter of 2016 as well as one-time project reimbursements of $8 million recognized in the third quarter of 2015.

These decreases were partially offset by a $3 million increase in crude oil gathering margins due to higher gathered volumes in the Williston basin and a $7 million increase in natural gas gathering margins primarily due to increased billings under minimum volume commitments.

Our gathering and processing segment operation and maintenance and general and administrative expenses decreased $12 million. The decrease was primarily due to cost reduction efforts, including a $5 million decrease in payroll related costs, a $2 million reduction in equipment rentals and a $1 million reduction in other operating costs as well as a $1 million decrease in severance charges related to workforce reductions announced in 2015. Additionally, one-time project reimbursement expenses of $5 million were recognized for the three months ended September 30, 2015 for which there were no comparable expenses in the three months ended September 30, 2016. These decreases were partially offset by increased losses on the disposition of assets of $2 million.

Our gathering and processing segment recognized impairments of $8 million in the three months ended September 30, 2016 as compared to $514 million of impairments in the three months ended September 30, 2015. In the third quarter of 2016, we

Table of Contents

recognized impairments of $8 million on our Service Star business line as compared to the third quarter of 2015, in which we recognized $6 million of impairments related to our Service Star business line. Additionally, in the third quarter of 2015, we determined that the carrying value of goodwill associated with the gathering and processing reportable segment was completely impaired and as a result recognized an impairment of $508 million.

Nine months ended September 30, 2016 compared to nine months ended September 30, 2015. Our gathering and processing segment reported operating income of $142 million in the nine months ended September 30, 2016 compared to an operating loss of $326 million in the nine months ended September 30, 2015. The difference of $468 million in operating income between periods was primarily due to $514 million of impairments recognized in the third quarter of 2015 related to goodwill and long-lived assets, compared to $8 million of impairments recognized in the third quarter of 2016 related to long-lived assets, a $24 million decrease in operation and maintenance and general and administrative expenses. These increases were partially offset by a $48 million decrease in gross margin, a $13 million increase in depreciation and amortization and a $1 million increase in taxes other than income tax during the nine months ended September 30, 2016.

Our gathering and processing segment revenues decreased $104 million. The decrease was primarily due to a $70 million reduction in revenues from sales of natural gas as a result of lower average natural gas prices and lower gathered volumes, $23 million in changes to the fair value of condensate and NGL derivatives and a $15 million decrease in revenues from NGL sales resulting from lower average NGL prices in the nine months ended September 30, 2016, as well as one-time project reimbursements of $12 million recognized in the third quarter of 2015. These decreases were partially offset by a $15 million increase in crude oil gathering revenues due to higher gathered volumes in the Williston basin.

Our gathering and processing segment gross margin decreased $48 million. The decrease was primarily due to $23 million in changes in the fair value of condensate and NGL derivatives, an $18 million decrease in processing margins resulting from lower average NGL prices and lower processed volumes in the Ark-La-Tex basin offset by higher processed volumes in the Anadarko basin, a $13 million decrease in natural gas sales due to lower average natural gas prices, a $2 million decrease in third party measurement and communication services and a $1 million decrease in natural gas gathering margins as a result of lower gathered volumes, net of increased billings under minimum volume commitments. Additionally, there was a decrease of $12 million related to one-time project reimbursements during the nine months ended September 30, 2015. These decreases were partially offset by a $9 million increase in the imbalance receivable associated with our annual fuel rate determination and a $12 million increase in crude oil gathering margin due to higher gathered volumes in the Williston basin.

Our gathering and processing segment operation and maintenance and general and administrative expenses decreased $24 million. The decrease was primarily due to cost reduction efforts, including a $6 million decrease in employee expenses, a $4 million reduction in materials and supplies costs, a $4 million reduction in equipment rentals, a $3 million decrease in payroll related costs and a $5 million reduction of other operating costs as well as a $3 million decrease in severance charges related to workforce reductions announced in 2015. Additionally, one-time project reimbursement expenses of $5 million were recognized for the nine months ended September 30, 2015 for which there were no comparable expenses in the nine months ended September 30, 2016. These decreases were partially offset by $4 million in increased losses on the disposition of assets and a $2 million increase in allowance for doubtful accounts.

Our gathering and processing segment depreciation and amortization increased $13 million due to additional assets placed in service.

Our gathering and processing segment recognized impairments of $8 million in the nine months ended September 30, 2016 as compared to $514 million of impairments in the nine months ended September 30, 2015. In the third quarter of 2016, we recognized impairments of $8 million on our Service Star business line as compared to the third quarter of 2015, in which we recognized $6 million of impairments related to our Service Star business line. Additionally, in the third quarter of 2015, we determined that the carrying value of goodwill associated with the gathering and processing reportable segment was completely impaired and as a result recognized an impairment of $508 million.

Our gathering and processing segment taxes other than income tax increased $1 million due to higher estimated ad valorem taxes.

Transportation and Storage

Three Months Ended September 30, 2016 compared to three months ended September 30, 2015. Our transportation and storage segment reported operating income of $62 million in the three months ended September 30, 2016 compared to an operating loss of $546 million in the three months ended September 30, 2015. The difference of $608 million of operating income between periods was primarily due to $591 million of impairments recognized in the third quarter of 2015 related to goodwill and long-lived assets, a $9 million decrease in operation and maintenance and general and administrative expenses, a $6 million increase in gross margin and a $2 million decrease in taxes other than income tax for the three months ended September 30, 2016.

Our transportation and storage segment revenues decreased $14 million. The decrease was primarily due to a $24 million decrease in revenues from natural gas sales associated with lower sales volumes and lower average sales prices. These decreases were partially offset by $8 million in changes to the fair value of natural gas derivatives, a $1 million increase in transportation services for local distribution companies and $1 million of higher revenues from off-system transportation.

Our transportation and storage segment gross margin increased $6 million. The increase was primarily due to $8 million of changes in the fair value of natural gas derivatives, a $1 million increase in margins on transportation services for local distribution companies and a $1 million increase in margins from off-system transportation services. These increases were partially offset by a $3 million decrease in system management activities and a $1 million decrease in margins from firm transportation services for the three months ended September 30, 2016.

Our transportation and storage segment operation and maintenance and general and administrative expenses decreased $9 million. The decrease was primarily due to cost reduction efforts, including a $7 million decrease in materials and supplies costs, a $2 million decrease in integration and other contract services costs and a $1 million decrease in payroll related costs as well as $2 million decrease in severance charges related to workforce reductions announced in 2015. These decreases were partially offset by a $3 million increase in losses on disposition of assets.

Our transportation and storage segment recognized no impairments in the three months ended September 30, 2016 as compared to $591 million of impairments in the three months ended September 30, 2015. In the third quarter of 2015, we determined that the carrying value of goodwill associated with the transportation and storage reportable segment was completely impaired and as a result recognized an impairment of $579 million. Additionally, in the third quarter of 2015, we recognized an impairment on jurisdictional pipeline assets of $12 million.

Our transportation and storage segment taxes other than income tax decreased $2 million due to favorable ad valorem assessments and appeal efforts.

Our transportation and storage segment equity in earnings of equity method affiliate increased $1 million related to our interest in SESH.

Nine months ended September 30, 2016 compared to nine months ended September 30, 2015. Our transportation and storage segment reported operating income of $157 million in the nine months ended September 30, 2016 compared to an operating loss of $452 million in the nine months ended September 30, 2015. The difference of $609 million in operating income between periods was primarily due to $591 million of impairments recognized in the third quarter of 2015 related to goodwill and long-lived assets, a $23 million decrease in operation and maintenance and general and administrative expenses and a $3 million decrease in taxes other than income tax. These increases were partially offset by a $6 million decrease in gross margin and a $2 million increase in depreciation and amortization expenses for the nine months ended September 30, 2016.

Our transportation and storage segment revenues decreased $119 million. The decrease was primarily due to a $108 million decrease in revenues from lower natural gas sales associated with lower sales volumes and lower average sales prices and $6 million of changes in the fair value of natural gas derivatives.

Our transportation and storage segment gross margin decreased $6 million. The decrease was primarily due to a decrease of $7 million in firm transportation margins, $6 million of changes in the fair value of natural gas derivatives and a $2 million decrease in off-system transportation margins. These decreases were partially offset by a $4 million increase in system management activities and a $5 million increase in margins on transportation services for local distribution companies.

Our transportation and storage segment operation and maintenance and general and administrative expenses decreased $23 million. The decrease was primarily due cost reduction efforts, including $8 million in lower integration and other contract services costs, an $8 million decrease in materials and supplies costs and a $6 million decrease in payroll related costs as well as $4 million in lower severance charges related to workforce reductions announced in 2015. These decreases were partially offset by a $3 million increase in losses on dispositions of assets.

Our transportation and storage segment depreciation and amortization increased $2 million primarily due to additional assets placed in service.

Table of Contents

Our transportation and storage segment recognized no impairments in the nine months ended September 30, 2016 as compared to $591 million of impairments in the nine months ended September 30, 2015. In the third quarter of 2015, we determined that the carrying value of goodwill associated with the transportation and storage reportable segment was completely impaired and as a result recognized an impairment of $579 million. Additionally, in 2015 we recognized an impairment on jurisdictional pipeline assets of $12 million.

Our transportation and storage segment taxes other than income tax decreased $3 million due to favorable ad valorem assessments and appeal efforts.

Our transportation and storage segment equity in earnings of equity method affiliate increased $1 million related to our interest in SESH.

Condensed Consolidated Interim Information

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions)			
Operating Income (Loss)	$139	$(975)	$299	$(778)
Other Income (Expense):				
Interest expense	(26)	(23)	(74)	(66)
Equity in earnings of equity method affiliate	8	7	22	21
Other, net	—	—	—	2
Total Other Expense	(18)	(16)	(52)	(43)
Income (Loss) Before Income Taxes	121	(991)	247	(821)
Income tax expense	2	—	3	2
Net Income (Loss)	$119	$(991)	$244	$(823)
Less: Net income (loss) attributable to noncontrolling interest	—	(6)	—	(6)
Net Income (Loss) attributable to limited partners	$119	$(985)	$244	$(817)
Less: Series A Preferred Unit distributions	9	—	13	—
Net Income (Loss) attributable to common and subordinated units	$110	$(985)	$231	$(817)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions)			
Other Financial Data:				
Gross margin [1]	$352	$359	$941	$996
Adjusted EBITDA [1]	244	222	655	629
DCF [1]	189	154	507	438

(1) Gross margin, Adjusted EBITDA and DCF are non-GAAP measures and are defined and reconciled to their most directly comparable financial measures calculated and presented below under the caption Non-GAAP Financial Measures within this Part I, Item 2.

Three Months Ended September 30, 2016 compared to Three Months Ended September 30, 2015

Net Income attributable to limited partners. We reported net income attributable to limited partners of $119 million in the three months ended September 30, 2016 compared to net loss attributable to limited partners of $985 million in the three months ended September 30, 2015. The increase in net income attributable to limited partners of $1,104 million was primarily attributable to an increase in operating income of $1,114 million related to the 2015 impairment, partially offset by an increase in interest expense of $3 million, in the three months ended September 30, 2016.

Table of Contents

Interest Expense. Interest expense increased $3 million due to higher interest rates on the Partnership’s outstanding debt and an increase in the amount of outstanding variable rate debt.

Nine Months Ended September 30, 2016 compared to Nine Months Ended September 30, 2015

Net Income attributable to limited partners. We reported net income attributable to limited partners of $244 million in the nine months ended September 30, 2016 compared to net loss attributable to limited partners of $817 million in the nine months ended September 30, 2015. The increase in net income attributable to limited partners of $1,061 million was primarily attributable to an increase in operating income of $1,077 million related to the 2015 impairment, partially offset by an increase in interest expense of $8 million and a decrease in other income and expense of $2 million in the nine months ended September 30, 2016.

Interest Expense. Interest expense increased $8 million due to higher interest rates on the Partnership’s outstanding debt and an increase in the amount of outstanding variable rate debt.

Non-GAAP Financial Measures

The Partnership has included the non-GAAP financial measures Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio in this report based on information in its condensed consolidated financial statements.

Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio are supplemental financial measures that management and external users of the Partnership’s financial statements, such as industry analysts, investors, lenders and rating agencies may use, to assess:

- The Partnership’s operating performance as compared to those of other publicly traded partnerships in the midstream energy industry, without regard to capital structure or historical cost basis;
- The ability of the Partnership’s assets to generate sufficient cash flow to make distributions to its partners;
- The Partnership’s ability to incur and service debt and fund capital expenditures; and
- The viability of acquisitions and other capital expenditure projects and the returns on investment of various investment opportunities.

This report includes a reconciliation of Gross margin to total revenues, Adjusted EBITDA and DCF to net income attributable to limited partners, and Adjusted EBITDA to net cash provided by operating activities and Adjusted interest expense to interest expense, the most directly comparable GAAP financial measures, on a historical basis, as applicable, for each of the periods indicated. Distribution coverage ratio is a financial performance measure used by management to reflect the relationship between the Partnership's financial operating performance and cash distribution. The Partnership believes that the presentation of Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio provides information useful to investors in assessing its financial condition and results of operations. Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio should not be considered as alternatives to net income, operating income, total revenue, cash flow from operating activities, interest expense or any other measure of financial performance or liquidity presented in accordance with GAAP. Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio have important limitations as analytical tools because they exclude some but not all items that affect the most directly comparable GAAP measures. Additionally, because Gross margin, Adjusted EBITDA, Adjusted interest expense, DCF and Distribution coverage ratio may be defined differently by other companies in the Partnership’s industry, its definitions of Gross margin, Adjusted EBITDA. Adjusted interest expense, DCF and Distribution coverage ratio may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

38

Table of Contents

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions)			
Reconciliation of Gross Margin to Total Revenues:				
Consolidated				
Product sales	$326	$357	$837	$1,043
Service revenue	294	289	821	809
Total Revenues	620	646	1,658	1,852
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	268	287	717	856
Gross margin	$352	$359	$941	$996
Reportable Segments				
Gathering and Processing				
Product sales	$295	$299	$759	$875
Service revenue	160	157	416	404
Total Revenues	455	456	1,175	1,279
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	246	235	642	698
Gross margin	$209	$221	$533	$581
Transportation and Storage				
Product sales	$150	$166	$348	$467
Service revenue	135	133	408	408
Total Revenues	285	299	756	875
Cost of natural gas and natural gas liquids (excluding depreciation and amortization)	141	161	346	459
Gross margin	$144	$138	$410	$416

Table of Contents

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions, except Distribution coverage ratio)			
Reconciliation of Adjusted EBITDA and DCF to net income (loss) attributable to limited partners and calculation of Distribution coverage ratio:				
Net income (loss) attributable to limited partners	$119	$(985)	$244	$(817)
Add:				
Depreciation and amortization expense	84	84	248	233
Interest expense, net of interest income	26	23	74	66
Income tax expense	2	—	3	2
EBITDA	$231	$(878)	$569	$(516)
Add:				
Distributions from equity method affiliate[(1)]	13	10	40	37
Non-cash equity based compensation	4	1	9	7
Other non-cash losses[(2)]	3	4	61	30
Impairments	8	1,105	8	1,105
Less:				
Other non-cash gains[(3)]	(7)	(7)	(10)	(7)
Noncontrolling Interest Share of Adjusted EBITDA	—	(6)	—	(6)
Equity in earnings of equity method affiliate	(8)	(7)	(22)	(21)
Adjusted EBITDA	$244	$222	$655	$629
Less:				
Series A Preferred Unit distributions[(4)]	(9)	—	(22)	—
Adjusted interest expense[(5)]	(27)	(27)	(76)	(77)
Maintenance capital expenditures	(21)	(41)	(51)	(113)
Current income taxes	2	—	1	(1)
DCF	$189	$154	$507	$438
Distributions related to common and subordinated unitholders[(6)]	$134	$134	$402	$400
Distribution coverage ratio	1.41	1.15	1.26	1.10

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(1) Distributions from equity method affiliate includes an $8 million and $7 million return on investment and a $5 million and $3 million return of investment for the three months ended September 30, 2016 and 2015, respectively. Distributions from equity method affiliate includes a $22 million and $26 million return on investment and an $18 million and $11 million return of investment for the nine months ended September 30, 2016 and 2015, respectively. Equity in earnings of equity method affiliate, net of distributions only includes those distributions representing a return on investment.

(2) Other non-cash losses includes decreases in the fair value of derivatives, lower of cost or net realizable value adjustments, loss on sale of assets and write-downs of materials and supplies.

(3) Other non-cash gains includes lower of the cost or net realizable value adjustment recoveries upon the sale of the related inventory and increases in the fair value of derivatives.

(4)

This amount represents the quarterly cash distributions on the Series A Preferred Units declared for the three and nine months ended September 30, 2016. In accordance with the Partnership Agreement, the Series A Preferred Unit distributions are deemed to have been paid out of available cash with respect to the quarter immediately preceding the quarter in which the distribution is made.

(5) See below for a reconciliation of Adjusted interest expense to Interest expense.

(6) Represents cash distributions declared for common and subordinated units outstanding as of each respective period. Amounts for 2016 reflect estimated cash distributions for common and subordinated units outstanding for the quarter ended September 30, 2016.

Table of Contents

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In millions)			
Reconciliation of Adjusted EBITDA to net cash provided by operating activities:				
Net cash provided by operating activities	$209	$207	$498	$491
Interest expense, net of interest income	26	23	74	66
Net loss attributable to noncontrolling interest	—	6	—	6
Income tax expense	2	—	3	2
Deferred income tax expense (benefit)	(4)	—	(4)	(1)
Equity in earnings of equity method affiliate, net of distributions[(1)]	—	(3)	—	(16)
Impairments	(8)	(1,105)	(8)	(1,105)
Non-cash equity based compensation	(4)	(1)	(9)	(7)
Other non-cash items	(1)	4	(7)	11
Changes in operating working capital which (provided) used cash:				
Accounts receivable	47	37	25	35
Accounts payable	4	12	88	82
Other, including changes in noncurrent assets and liabilities	(40)	(58)	(91)	(80)
EBITDA	$231	$(878)	$569	$(516)
Add:				
Non-cash equity based compensation	4	1	9	7
Distributions from equity method affiliate[(1)]	13	10	40	37
Impairments	8	1,105	8	1,105
Other non-cash losses[(2)]	3	4	61	30
Less:				
Other non-cash gains[(3)]	(7)	(7)	(10)	(7)
Noncontrolling Interest Share of Adjusted EBITDA	—	(6)	—	(6)
Equity in earnings of equity method affiliate	(8)	(7)	(22)	(21)
Adjusted EBITDA	$244	$222	$655	$629

(1) Distributions from equity method affiliate includes an $8 million and $7 million return on investment and a $5 million and $3 million return of investment for the three months ended September 30, 2016 and 2015, respectively. Distributions from equity method affiliate includes a $22 million and $26 million return on investment and an $18 million and $11 million return of investment for the nine months ended September 30, 2016 and 2015, respectively. Equity in earnings of equity method affiliate, net of distributions only includes those distributions representing a return on investment.

(2) Other non-cash losses includes decreases in the fair value of derivatives, lower of cost or net realizable value adjustments, loss on sale of assets and write-downs of materials and supplies.

(3) Other non-cash gains includes lower of the cost or net realizable value adjustment recoveries upon the sale of the related inventory and increases in the fair value of derivatives.

	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
	(In millions)			
Reconciliation of Adjusted interest expense to Interest expense:				
Interest Expense	$26	$23	$74	$66
Add:				
Amortization of premium on long-term debt	1	2	4	4
Capitalized interest on expansion capital	—	3	1	9
Less:				
Amortization of debt costs	—	(1)	(3)	(2)
Adjusted interest expense	$27	$27	$76	$77

Liquidity and Capital Resources

Working Capital

Working capital is the difference in our current assets and our current liabilities. Working capital is an indication of liquidity and potential need for short-term funding. The change in our working capital requirements are driven generally by changes in accounts receivable, accounts payable, commodity prices, credit extended to, and the timing of collections from, customers, and the level and timing of spending for maintenance and expansion activity. As of September 30, 2016, we had a working capital surplus of $70 million. We utilize our revolving credit facility to manage the timing of cash flows and fund short-term working capital deficits.

Cash Flows

The following tables reflect cash flows for the applicable periods:

	Nine Months Ended September 30, 2016	2015
	(In millions)	
Net cash provided by operating activities	$498	$491
Net cash used in investing activities	(270)	(730)
Net cash provided by (used in) financing activities	(209)	232