Enable Midstream Partners, LP
Form 10-K
February 18, 2015
Table of Contents

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

FORM 10-K

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES AND EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014
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 950
Oklahoma City, Oklahoma 73102
(Address of principal executive offices) (Zip Code)
Registrant's telephone number, including area code: (405) 525-7788

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Units Representing Limited Partner Interests	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
o Yes þ No
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.
o Yes þ No
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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

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	¨	Accelerated filer	¨
Non-accelerated filer	þ (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

The aggregate market value of the Common Units representing limited partner interests held by non-affiliates of the registrant, based upon the closing price of $26.19 per common limited partner unit on June 30, 2014, was approximately $2,028 million.

As of February 2, 2015, there were 214,455,154 common units and 207,855,430 subordinated units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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

	Page
GLOSSARY OF TERMS	1
FORWARD-LOOKING STATEMENTS	4
Part I	
Item 1. Business	5
Item 1A. Risk Factors	26
Item 1B. Unresolved Staff Comments	51
Item 2. Properties	51
Item 3. Legal Proceedings	52
Item 4. Mine Safety Disclosures	52
Part II	
Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	52
Item 6. Selected Financial Data	55
Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations	57
Item 7A. Quantitative and Qualitative Disclosures About Market Risk	83
Item 8. Financial Statements and Supplementary Data	84
Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	123
Item 9A. Controls and Procedures	123
Item 9B. Other Information	123
Part III	
Item 10. Directors, Executive Officers and Corporate Governance	124
Item 11. Executive Compensation	128
Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	141
Item 13. Certain Relationships and Related Transactions, and Director Independence	143
Item 14. Principal Accounting Fees and Services	148
Part IV	
Item 15. Exhibits, Financial Statement Schedules	149
Signatures	151

Table of Contents

GLOSSARY

2011 Pipeline Safety Act.	Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011.
Adjusted EBITDA.	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.
APSA.	Accountable Pipeline Safety and Partnership Act of 1996.
ArcLight.	ArcLight Capital Partners, LLC, a Delaware limited liability company, its affiliated entities ArcLight Energy Partners Fund V, L.P., ArcLight Energy Partners Fund IV, L.P., Bronco Midstream Partners, L.P., Bronco Midstream Infrastructure LLC and Enogex Holdings LLC, and their respective general partners and subsidiaries.
ASU.	Accounting Standards Update.
Barrel.	42 U.S. gallons of petroleum products.
Bbl.	Barrel.
Bbl/d.	Barrels per day.
Bcf.	Billion cubic feet.
Bcf/d.	Billion cubic feet per day.
Board of Directors.	The board of directors of Enable GP, LLC.
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.
CAA.	Clean Air Act, as amended.
CEFS.	CenterPoint Energy Field Services, LLC, a Delaware limited liability company, that was converted into a Delaware limited partnership that became the Partnership.
CenterPoint Energy.	CenterPoint Energy, Inc., a Texas corporation, and its subsidiaries, other than Enable Midstream Partners, LP.
CERCLA.	Comprehensive Environmental Response, Compensation and Liability Act of 1980.
CFTC.	Commodity Futures Trading Commission.
COBRA.	Consolidated Omnibus Budget Reconciliation Act of 1985.
Code.	The Internal Revenue Code of 1986, as amended.
Condensate.	A natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.
Delaware Act.	Delaware Revised Uniform Limited Partnership Act.
DHS.	Department of Homeland Security.
Dodd-Frank Act.	Dodd-Frank Wall Street Reform and Consumer Protection Act.
DOT.	Department of Transportation.
EGT.	Enable Gas Transmission, LLC, a wholly owned subsidiary of the Partnership that operates a 5,946-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.
EIA.	Energy Information Administration.
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.
Enable Oklahoma.	Enable Oklahoma Intrastate Transmission, LLC, formerly Enogex LLC, a wholly owned subsidiary of the Partnership that operates a 2,241-mile intrastate pipeline that provides natural gas transportation and storage services to customers in Oklahoma.
Enogex.	

	Enogex LLC, a Delaware limited liability company, that was contributed to the Partnership on May 1, 2013.
ESA.	Endangered Species Act.
EPA.	Environmental Protection Agency.
EPAct of 2005.	Energy Policy Act of 2005.

Table of Contents

ERISA.	Employee Retirement Income Security Act of 1974.
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.
GHG.	Greenhouse gas.
Gross margin.	Total revenues minus cost of goods sold, excluding depreciation and amortization.
HCA.	High-consequence area.
HLPSA.	Hazardous Liquid Pipeline Safety Act of 1979.
Hinshaw pipeline.	A pipeline that is exempt from FERC's NGA regulation if its operations are within a single state, if any gas received from interstate sources is received within the state and if its service is regulated by the state commission.
ICA.	Interstate Commerce Act.
IRS.	Internal Revenue Service.
LDC.	Local distribution company involved in the delivery of natural gas to consumers within a specific geographic area.
Lean gas.	Natural gas that is primarily methane without NGLs.
LIBOR.	London Interbank Offered Rate.
LNG.	Liquefied natural gas.
MAOP.	Maximum allowable operating pressure for gas pipelines.
MBbl/d.	Thousand barrels per day.
MFA.	Master Formation Agreement dated as of March 14, 2013 by and among CenterPoint Energy, Inc., OGE Energy Corp., Bronco Midstream Holdings, LLC and Bronco Midstream Holdings II, LLC
MMcf.	Million cubic feet of natural gas.
MMBtu.	Million British thermal units.
MMcf/d.	Million cubic feet per day.
MOP.	Maximum operating pressure for hazardous liquid pipelines.
MRT.	Enable Mississippi River Transmission, LLC, a wholly owned subsidiary of the Partnership that operates a 1,663-mile interstate pipeline that provides natural gas transportation and storage services principally in Texas, Arkansas, Louisiana, Missouri and Illinois.
NEPA.	National Environmental Policy Act.
NGA.	Natural Gas Act of 1938.
NGPA.	Natural Gas Policy Act of 1978.
NGPSA.	Natural Gas Pipeline Safety Act of 1968.
NGLs.	Natural gas liquids, which are the hydrocarbon liquids contained within natural gas including condensate.
NYMEX.	New York Mercantile Exchange.
NYSE.	New York Stock Exchange.
OCC.	Oklahoma Corporation Commission.
Offering.	Initial public offering of Enable Midstream Partners, LP.
OGE Energy.	OGE Energy Corp., an Oklahoma corporation, and its subsidiaries, other than Enable Midstream Partners, LP.

OPA.	Oil Pollution Act.

Table of Contents

OSHA.	Occupational Safety and Health Act of 1970.
Partnership.	Enable Midstream Partners, LP.
PDO.	Petition for a Declaratory Order. Petition filed with FERC to seek regulatory assurances for key terms of service offered during an open season.
PHMSA.	Pipeline and Hazardous Materials Safety Administration.
PIPES Act.	Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006.
Prospectus Directive.	Directive 2003/71/EC and amendments thereto.
PSA.	Pipeline Safety Act of 1992.
PSIA.	Pipeline Safety Improvement Act of 2002.
PVIR.	Preventable Vehicle Incident Rate.
RCRA.	Resource Conservation and Recovery Act of 1976.
RICE MACT.	Reciprocating internal combustion engines maximum achievable control technology.
Rich gas.	Natural gas containing higher concentrations of NGLs that is usually produced in association with crude oil.
SCOOP.	South Central Oklahoma Oil Province.
SDWA.	Safe Drinking Water Act.
SEC.	Securities and Exchange Commission.
Securities Act.	Securities Act of 1933, as amended.
SESH.	Southeast Supply Header, LLC, in which the Partnership owns a 49.90% interest at December 31, 2014, that operates a 286-mile interstate natural gas pipeline from Perryville, Louisiana to southwestern Alabama near the Gulf Coast.
Sponsors.	CenterPoint Energy and OGE Energy.
Superfund.	Comprehensive Environmental Response, Compensation and Liability Act of 1980.
Tailoring Rule.	Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule. Phases in permitting requirements for stationary sources of GHGs.
TBtu.	Trillion British thermal units.
TBtu/d.	Trillion British thermal units per day.
Tcf.	Trillion cubic feet of natural gas.
Term Loan Facility.	$1.05 billion senior unsecured term loan facility.
TRIR.	Total Recordable Incident Rate.
WTI.	West Texas Intermediate.
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.

3

Table of Contents

FORWARD-LOOKING STATEMENTS

Some of the information in this report may contain forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. 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," "plan," "estimate, "believe," "project," "budget," "potential," or "continue," and similar expressions are used to identify forward-looking 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. Those risk factors and other factors noted throughout this 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;
- operating hazards and other risks incidental to transporting, storing and gathering 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.

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.

4

Table of Contents

PART I

Item 1. Business

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 service primarily to natural gas producers, utilities and industrial customers.

Our natural gas gathering and processing assets are located in four states and serve natural gas production from shale developments in the Anadarko, Arkoma and Ark-La-Tex basins. We also own a crude oil gathering business in the Bakken Shale formation of the Williston Basin that commenced initial operations in November 2013. Our natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

We were formed in May 2013 as a limited partnership among CenterPoint Energy, OGE Energy and ArcLight. As of December 31, 2014, our portfolio of energy infrastructure assets included approximately 11,900 miles of gathering pipelines, 12 major processing plants with approximately 2.1 Bcf/d of processing capacity, approximately 7,900 miles of interstate pipelines (including SESH), approximately 2,300 miles of intrastate pipelines and eight storage facilities providing approximately 87.5 Bcf of storage capacity. Based on our scale, we believe we are able to provide our customers with fully integrated midstream services from the wellhead to the marketplace.

For the year ended December 31, 2014, approximately 72% of our gross margin was generated from contracts that are fee-based, and approximately 50% of our gross margin was attributable to fees associated with firm contracts or contracts with minimum volume commitment features.

Our website address is www.enablemidstream.com. Documents and information on our website are not incorporated by reference in this report. Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed with or furnished to the SEC are available, free of charge, on our website soon after we file or furnish such material.

Business Strategies

Our primary business objective is to practice commercial and operational excellence and to grow our business responsibly, enabling us to increase the amount of cash distributions we make to our unitholders over time while maintaining our financial stability. We intend to accomplish this objective by executing the strategies listed below:

- Capitalize on Organic Growth Opportunities Associated with Our Strategically Located Assets. We own and operate assets servicing four of the largest basins in the United States, including some of the most productive shale plays in these basins. We expect to grow our business and distributable cash flow by developing new energy infrastructure projects to support new and existing customers as they expand beyond our current footprint. As a result of this expanding activity, we are constructing natural gas gathering and compression infrastructure, crude oil gathering infrastructure, and two additional processing facilities in Oklahoma that are expected to provide an additional 400

MMcf/d of processing capacity. For the year ended December 31, 2014, we invested $669 million in expansion capital expenditures.

- Continue to Minimize Direct Commodity Price Exposure Through Long-Term, Fee-Based Contracts. We continually seek ways to minimize our exposure to commodity price risk, and management believes that our focus on fee-based revenues reduces our direct commodity price exposure and is essential to maintaining stable cash flows and increasing our quarterly distributions over time. Since 2009, we have focused on increasing the percentage of long-term, fee-based contracts with our customers. For the year ended December 31, 2014, 72% of our gross margin was generated from fee-based contracts. As we grow, we intend to maintain our focus on long-term, fee-based contracts.
- Maintain Strong Customer Relationships to Attract New Volumes and Expand Beyond Our Existing Asset Footprint and Business Lines. We plan to grow our business through our strong relationships with existing customers. Management believes that we have built a strong and loyal customer base through exemplary customer service and reliable project execution. We have invested in multiple organic growth projects in support of our existing and new customers. We

Table of Contents

expect to maintain and build relationships with key producers and suppliers to continue to attract new volumes and expansion opportunities.

- Grow Through Accretive Acquisitions and Disciplined Development. We plan to pursue accretive acquisitions of complementary assets that provide attractive potential returns in new operating regions or midstream business lines. We will continue to analyze acquisition opportunities using disciplined financial and operating practices, including a process for evaluating and managing risks to cash distributions.
- Leverage the Scale of Our Existing Assets to Realize Significant Synergies. Given the complementary features of our assets, we expect operating synergies from the interconnection and optimization of our systems to increase our cash flows over time.

Our Sponsors

CenterPoint Energy and OGE Energy are aligned with us to grow our distributions. CenterPoint and OGE Energy own a significant interest in us through their approximate 55.4% and 26.3% limited partner interests in us, respectively. CenterPoint Energy and OGE Energy each own 50% of the management rights of our general partner, which holds all of our incentive distribution rights. In addition, CenterPoint Energy and OGE Energy own 40% and 60%, respectively, of the economic rights in our general partner.

CenterPoint Energy (NYSE: CNP) is a public utility holding company whose indirect wholly owned subsidiaries include (i) CenterPoint Energy Houston Electric, LLC, which provides electric transmission and distribution services to retail electric providers serving over two million metered customers in a 5,000-square- mile area of the Texas Gulf Coast that has a population of approximately six million people and includes the city of Houston; and (ii) CenterPoint Energy Resources Corp., which owns and operates natural gas distribution systems serving more than three million customers in six states, including customers in the metropolitan areas of Houston, Texas; Minneapolis, Minnesota; Little Rock, Arkansas; Shreveport, Louisiana; Biloxi, Mississippi; and Lawton, Oklahoma.

OGE Energy (NYSE: OGE) is the parent company of OG&E, a regulated electric utility serving approximately 805,000 customers in a service territory spanning 30,000 square miles in Oklahoma and western Arkansas. OG&E furnishes retail electric service in 267 communities and their contiguous rural and suburban areas. OG&E’s service area includes Oklahoma City, Oklahoma and Fort Smith, Arkansas, the second largest city in that state. Of the 267 communities that OG&E serves, 241 are located in Oklahoma and 26 are located in Arkansas.

Our sponsors are also significant customers of our transportation and storage segment and continue to own and operate a substantial portfolio of energy assets. For the year ended December 31, 2014, approximately 3% of our total gross margin was derived from contracts with OGE Energy servicing electric power generation. For the year ended December 31, 2014, approximately 6% of our total gross margin was derived from contracts servicing LDCs owned by CenterPoint Energy.

Our sponsors entered into a number of agreements in connection with our formation. Please read Item 13. “Certain Relationships and Related Party Transactions” for a detailed description of these agreements, as well as other agreements affecting us and our sponsors. Although management believes our relationships with CenterPoint Energy and OGE Energy are positive attributes, there can be no assurance that we will benefit from these relationships.

Our Assets and Operations

Our assets and operations are organized into two reportable segments: gathering and processing, and transportation and storage.

6

Gathering and Processing

General. We own and operate approximately 11,900 miles of natural gas gathering pipelines in the Anadarko, Arkoma and Ark-La-Tex basins with approximately 853,000 horsepower of compression and 12 natural gas processing plants with approximately 2.1 Bcf/d of processing capacity and 2.1 Bcf/d of treating capacity as of December 31, 2014. We provide gathering, compression, treating, dehydration, processing and NGL fractionation for producers who are active in the areas in which we operate. For the year ended December 31, 2014, our assets gathered an average of approximately 3.34 TBtu/d of natural gas. For the year ended December 31, 2014, we processed approximately 1.56 TBtu/d of natural gas and produced approximately 66.74 MBbl/d of NGLs. We also have a crude oil gathering business in the Bakken Shale formation, principally located in the Williston Basin, that commenced initial operations in November 2013.

We serve shale developments in the United States through our operations in the following basins:

- Anadarko Basin (Oklahoma, Texas Panhandle). We currently operate in the liquids-rich Granite Wash, Cleveland, Tonkawa, Cana Woodford, SCOOP and Mississippi Lime plays. As of December 31, 2014, our assets include approximately 7,300 miles of natural gas gathering pipelines and nine natural gas processing plants with approximately 1,445 MMcf/d of processing capacity. We also have two processing plants under construction that will add 400 MMcf/d of processing capacity. For the year ended December 31, 2014, this system had average daily gathered throughput of approximately 1.38 TBtu/d of natural gas and produced 51,561 Bbl/d of NGLs. We currently serve over 200 producers in these areas and have secured 4.3 million gross acres dedicated under long-term contracts in this basin. The majority of these arrangements are fee-based with long-term acreage dedications. These contracts provide for gathering and compression services, which are typically fee-based, and processing services under fee-based, percent-of-liquids, percent-of-proceeds or keep-whole structures.
- Arkoma Basin (Oklahoma, Arkansas). In Oklahoma, we operate in the rich and lean gas areas of the western portion of the Arkoma basin. In Arkansas, we operate in the eastern Arkoma and the Fayetteville Shale play. As of December 31, 2014, our assets include approximately 2,900 miles of natural gas gathering pipelines and one natural gas processing plant with approximately 60 MMcf/d of processing capacity. For the year ended December 31, 2014, this system had average daily gathered throughput of approximately 0.77 TBtu/d of natural gas and produced 4,408 Bbl/d of NGLs. We currently serve over 85 producers in these areas and have secured over 1.4 million acres dedicated under long-term contracts in this basin. Additionally, in the lean gas area of the Fayetteville Shale we have secured fee-based contracts that provide minimum revenues in time periods when natural gas prices are depressed.
- Ark-La-Tex Basin (Arkansas, Louisiana and Texas). In Arkansas, Louisiana, and Texas, we operate primarily in the Haynesville, Cotton Valley and the lower Bossier plays. As of December 31, 2014, our assets include approximately 1,700 miles of natural gas gathering pipelines, two natural gas processing plants with approximately 545 MMcf/d of processing capacity, an NGL fractionation facility and approximately 40 miles of ethane pipelines. For the year ended December 31, 2014, this system had average daily gathered throughput of approximately 1.19 TBtu/d of natural gas

Table of Contents

and produced 10,770 Bbl/d of NGLs. We currently serve over 95 producers in these areas and have secured over 0.7 million gross acres dedicated under long-term contracts in this basin. Additionally, in the lean gas area of the Haynesville Shale we have secured contracts that are volume-based, providing minimum revenues in periods of time when natural gas prices are depressed.

- Williston Basin (North Dakota). In November 2013, we commenced operations on our initial crude oil gathering pipeline system, located in Dunn and McKenzie Counties in North Dakota, within the Bakken Shale formation. Additionally, in February 2014, we executed an agreement to gather crude oil production through a new system in Williams and Mountrail Counties in North Dakota that is expected to commence operations in the first quarter of 2015. During 2014, we placed most of the Dunn and McKenzie County crude oil gathering system into service and we expect to complete construction and place the Williams and Mountrail County system into service by the end of 2015. These systems will have a combined planned capacity of 49,500 barrels per day and are supported by over 0.2 million gross acres dedicated under a long-term, minimum volume commitment agreement with XTO Energy Inc. (XTO), an affiliate of Exxon Mobil Corporation, to provide crude oil gathering along with water transportation and other complementary services. For the year ended December 31, 2014, the Dunn and McKenzie County crude oil gathering system had average daily throughput of approximately 3.6 MBbl/d.

As of December 31, 2014, our processing infrastructure consisted of 12 plants located in the Anadarko, Arkoma and Ark-La-Tex basins. The assets serving the Anadarko basin consist of nine processing plants, seven of which are interconnected through our super-header system, and are configured to facilitate the flow of natural gas from western Oklahoma and the Wheeler County area in the Texas Panhandle to the Cox City, Thomas, McClure, Calumet, Clinton, South Canadian and Wheeler processing plants. We are also currently constructing two cryogenic processing facilities that we plan to connect to our super-header system in Grady County, Oklahoma, which are expected to add 400 MMcf/d of natural gas processing capacity. The first of the two new plants (the Bradley Plant) is a 200 MMcf/d plant that is expected to be completed in the first quarter of 2015. The second plant (the Grady County Plant) is a 200 MMcf/d plant that is expected to be completed in the first quarter of 2016. Our super-header system is intended to allow us to optimize the economics of our natural gas processing and to improve system utilization and reliability. The plant in the Arkoma basin serves the rich gas western portion of the area. The two plants in the Ark-La-Tex basin serve the Haynesville, Cotton Valley and Lower Bossier plays.

The following table sets forth certain information regarding our natural gas gathering and processing assets as of or for the year ended December 31, 2014:

Asset/Basin	Length (miles)	Compression (Horsepower)	Average Gathering Volume (TBtu/d)	Number of Processing Plants	Processing Capacity (MMcf/d)	NGLs Produced (Bbl/d)	Gross Acreage Dedications (in millions)
Anadarko Basin	7,345	558,636	1.38	9	1,445	51,561	4.3
Arkoma Basin	2,893	139,620	0.77	1	60	4,408	1.4
Ark-La-Tex Basin(1)	1,673	154,450	1.19	2	545	10,770	0.7
Total	11,911	852,706	3.34	12	2,050	66,739	6.4

(1) Ark-La-Tex basin assets also include 14,500 Bbl/d of fractionation capacity and 6,300 Bbl/d of ethane pipeline capacity, which are not listed in the table.

Table of Contents

The following table sets forth information with respect to our natural gas processing plants as of or for the year ended December 31, 2014:

Processing Plant	Year Installed		Type of Plant	Average Daily Inlet Volumes (MMcf/d)	Inlet Capacity (MMcf/d)	NGL Production Capacity (Bbl/d)(1)
Anadarko						
Grady County Plant	2016	(2)	Cryogenic	—	200	28,000
Bradley	2015	(3)	Cryogenic	—	200	28,000
McClure	2013		Cryogenic	157	200	22,000
Wheeler	2012		Cryogenic	196	200	22,000
South Canadian	2011		Cryogenic	189	200	26,000
Clinton	2009		Cryogenic	105	120	14,000
Roger Mills(4)	2008		Refrigeration	25	100	—
Canute	1996		Cryogenic	48	60	4,300
Cox City	1994		Cryogenic	157	180	14,500
Thomas	1981		Cryogenic	22	135	9,900
Calumet	1969		Lean Oil	68	250	8,000
Arkoma						
Wetumka	1983		Cryogenic	37	60	5,000
Ark-La-Tex						
Sligo(5)	2004		Refrigeration	55	225	1,400
Waskom	1940	(6)	Cryogenic	256	320	14,500
Total				1,315	2,450	197,600

(1) Excludes condensate capacity.
(2) The Grady County Plant is under construction and estimated to be in service in the first quarter of 2016.
(3) The Bradley Plant is under construction and estimated to be in service in the first quarter of 2015.
(4) All of our processing plants are located on properties that are owned by us except for Roger Mills, which is located on property that is leased.
(5) Average daily inlet volumes and inlet capacity includes 24 MMcf/d and 25MMcf/d, respectively, related to a separate cryogenic unit.
(6) A processing plant has been in operation on the Waskom plant site since 1940. The Waskom plant was upgraded to cryogenic in 1995.

Off-System Delivery Points. Our gathering lines interconnect with both our interstate and intrastate pipelines, as well as other interstate and intrastate pipelines, including the ETC Tiger, Acadian, Texas Eastern Transmission, Gulf South, Gulf Crossing, Panhandle Eastern, ANR, NGPL and Northern Natural pipelines. These connections provide producers with access to a diverse set of natural gas market hubs.

A significant amount of our NGLs are delivered into third-party pipelines and transported to Conway, Kansas or Mont Belvieu, Texas, where the NGLs are sold under contract or on the spot market. We sell the remaining NGLs as propane at the tailgate of three of our processing plants into local markets. Additionally, at our Waskom processing plant, we sell ethane, propane, butane and natural gasoline to local markets. Additionally, we operate a fractionator and an ethane pipeline.

The natural gas that remains after processing is primarily taken in-kind by the producer customers into our pipelines for redelivery either to on-system customers, such as electric generation facilities and other end-users, or into downstream interstate pipelines. NGLs are typically sold to NGL marketers and end-users, and condensate liquid production is typically sold to marketers and refineries.

Customers. We generate revenues from producers in the basins in which we operate. For the year ended December 31, 2014, our top gathering and processing customers by volumes gathered were affiliates of Encana Corporation (Encana), Apache Corporation (Apache), Vine Oil and Gas (Vine), Chesapeake Energy Corporation (Chesapeake), XTO, Continental Resources, Inc. (Continental), Devon Energy Production Company LP (Devon), Samson Resources Company (Samson), BP America Production Company (BP) and QEP Energy Company (QEP). For the year ended December 31, 2014, our top ten natural gas producer customers accounted for approximately 73% of our gathered volumes. The amounts for Vine reflect its acquisition of

Table of Contents

100% of the Royal Dutch Shell plc Haynesville assets in Louisiana during the fourth quarter of 2014, which included the assignment of our associated long term gas gathering and treating agreements.

Contracts. We derive revenue pursuant to a variety of arrangements, including fee-based, percent-of-proceeds, percent-of-liquids and keep-whole arrangements. For the year ended December 31, 2014, 49%, 44% and 7%, of our processing arrangements were fee-based, percent-of-proceeds and percent-of-liquids, and keep-whole, respectively.

For the year ended December 31, 2014, 59% of our gathering and processing gross margin was generated from gathering and processing fees. The remaining 41% of gross margin for the year ended December 31, 2014 came from commodities, including natural gas, natural gas liquids, and condensate received under percent-of-proceeds, percent-of-liquids and keep-whole arrangements. For the year ended December 31, 2014, contracts generating 26% of our gathering and processing gross margin had minimum volume commitments with remaining terms ranging from two to 15 years. Under a minimum volume commitment, a customer commits to ship a minimum volume of natural gas over a period of time on our gathering system, or, in lieu of shipping such volumes, to pay as if that minimum amount had been shipped.

As of December 31, 2014, our gathering agreements had acreage dedications with original terms ranging up to 15 years, which generally require that production by our customers within the acreage dedication be delivered to our gathering systems. As of December 31, 2014, our natural gas gathering agreements had acreage dedications of 6.4 million gross acres with a volume-weighted average remaining term of approximately eight years. In addition, as of December 31, 2014, we had minimum volume commitments in lean natural gas developments of 1.5 Bcf/d with weighted-average remaining terms of over six years.

We have the ability to enhance gross margin generated from our gathering and processing contracts through the use of multiple processing plant locations and our super-header system. Our large diameter, rich gas gathering pipelines in western Oklahoma are configured to allow natural gas from western Oklahoma and the Wheeler County area in the Texas Panhandle to flow to the Cox City, Thomas, McClure, Calumet, Clinton, South Canadian and Wheeler processing plants, and we have the ability to maximize margins from our contracts by choosing the most economical operational configuration given the market conditions at the time, including ethane rejection scenarios.

Competition. Competition to gather and process natural gas is primarily a function of gathering rate, processing value, system reliability, fuel rate, system run time, construction cycle time and prices at the wellhead. Our gathering and processing systems compete with gatherers and processors of all types and sizes, including those affiliated with various producers, other major pipeline companies and various independent midstream entities. In the process of selling NGLs, we compete against other natural gas processors extracting and selling NGLs. Our primary competitors are master limited partnerships who are active in the regions where we operate.

Transportation and Storage

We provide fee-based interstate and intrastate transportation and storage services across nine states. We own and operate approximately 7,900 miles (including SESH) of interstate transportation pipelines with average firm contracted capacity of 7.73 Bcf/d (excluding SESH), for the year ended December 31, 2014. In addition, we own and operate approximately 2,300 miles of intrastate transportation pipelines with average aggregate throughput of 1.61 TBtu/d for the year ended December 31, 2014.

We also own and operate eight natural gas storage facilities with approximately 87.5 Bcf of aggregate capacity and approximately 1.9 Bcf/d of aggregate daily deliverability as of December 31, 2014. In addition, we own an 8% contractual interest in Gulf South’s Bistineau storage facility located in Bienville Parish, Louisiana, with 8.0 Bcf of capacity and 100 MMcf/d of deliverability as of December 31, 2014. We also contract on a firm basis for 3.5 Bcf of high deliverability salt dome storage capacity from Cardinal in the Perryville and Arcadia natural gas storage fields. Our storage operations are located in Louisiana, Oklahoma and Illinois.

Both our intrastate and interstate storage facilities benefit customers by providing a full suite of storage services including no notice, load-following storage services and pipeline balancing. Our storage revenues are primarily fee-based and are derived from both firm and interruptible contracts. These contracts are often combined with transportation agreements to provide an overall solution for our customers. Our intrastate storage assets offer both fee-based firm and interruptible storage services. Interstate storage services offered by our intrastate storage facilities are provided at market-based rates under Section 311 of the NGPA pursuant to terms and conditions specified in our statements of operating conditions.

Table of Contents

The following table sets forth certain information regarding our transportation and storage assets as of December 31, 2014:

Asset	Length (miles)	Capacity			Total Firm Contracted Capacity(Bcf/d)	Average Throughput Volume (TBtu/d)		Percent of Capacity under Firm Contracts		Weighted Average Remaining Firm Contract Life(years)
Interstate Transportation[1]	7,896	8.5	Bcf	/d	7.73	3.4	[2]	93	%	3.5
Intrastate Transportation	2,286	1.9	Bcf	/d[3]	—	1.6		—		4.5
Storage	—	87.5	Bcf		65.10	—		74	%	3.3

(1) Except with respect to length, this information does not include amounts for SESH. SESH is a non-consolidated entity in which we own a 49.90% ownership interest.
(2) Actual volumes transported per day may be less than total firm contracted capacity based on demand.
(3) This represents the maximum single day receipts on the intrastate systems. Our Oklahoma intrastate pipeline system is a web-like configuration with multidirectional flow capabilities between numerous receipt and delivery points, which limits our ability to determine an overall system capacity. During the year ended December 31, 2014, the peak daily throughput was 1.9 TBtu/d or, on a volumetric basis, 1.9 Bcf/d.

We divide our transportation and storage assets into three categories: (1) interstate pipelines, (2) intrastate pipelines, and (3) storage. Our interstate pipelines consist of EGT, MRT and a 49.90% interest in the SESH pipeline. Our intrastate pipelines include the Enable Oklahoma Intrastate Transmission, LLC pipeline and the Enable Illinois Intrastate Transmission, LLC pipeline, which is operated commercially in conjunction with MRT.

Our transportation and storage assets were designed and built to serve large natural gas and electric utility companies in our areas of operation. For the year ended December 31, 2014, our top customers by gross margin were affiliates of CenterPoint Energy, Laclede Gas Company (Laclede), American Electric Power Co. (AEP), XTO, and OGE Energy. We also serve other utility customers such as Ameren Corporation (Ameren) and Entergy Corporation. Our EGT and MRT pipelines connect to our SESH pipeline in Perryville, Louisiana, where we perform our Perryville Hub™ services, which provides access to natural gas supplies from the Midcontinent, North Louisiana and East Texas and to natural gas-consuming markets in the Southeast, Northeast and Midwestern United States.

Table of Contents

Interstate Transportation

The following table sets forth certain information regarding our interstate transportation pipeline assets as of December 31, 2014:

Interstate Pipelines[1]

Asset	Length (miles)	Compression (Horsepower)	Average Throughput (TBtu/d)	Capacity (Bcf/d)	Storage Capacity (Bcf)
EGT	5,946	364,728	2.6	6.6	31.5
MRT	1,663	118,602	0.8	1.9	32.0
Total	7,609	483,330	3.4	8.5	63.5

____

(1) Excludes SESH, which is accounted for as an equity investment and described under "—Other Assets" below.

EGT

General. EGT is a 5,946-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. The system has the capacity to transport 6.6 Bcf/d of natural gas as of December 31, 2014. During the year ended December 31, 2014, we transported an average of approximately 2.6 TBtu/d, on this system. The system has pipeline diameters ranging from two to 42 inches and has 27 compressor stations. The system also had 31.5 Bcf of natural gas storage capacity as of December 31, 2014.

Off-System Delivery Points. Shippers on EGT have the ability to access almost every major natural gas-consuming market east of the Mississippi River. These include the growing Southeast power generation sector via SESH, as well as the ANR, SONAT, Tennessee Gas, Texas Gas, Texas Eastern, Gulf South, Trunkline, Columbia Gas and Midcontinent Express (MEP) pipelines, which are interconnected with EGT at Perryville, Louisiana, giving customers access to consuming markets in the Northeast and Midwest United States by utilizing our Perryville Hub™ services.

Customers. The primary customers for our EGT system are the local gas distribution divisions of CenterPoint Energy, gas producers who hold contracts for their Barnett and Haynesville Shale production, gas-fired power generators and other industrial and local third-party distribution companies. For the year ended December 31, 2014, approximately 26% of EGT's total operating gross margin was attributable to services provided to subsidiaries of CenterPoint Energy. EGT's customers are primarily located in Arkansas, Louisiana, Oklahoma and Texas.

Table of Contents

Contracts. EGT's services are typically provided under firm storage and transportation agreements. For the year ended December 31, 2014, approximately 49% of total transportation and storage segment gross margins were derived from demand charges under EGT's firm contract arrangements. As of December 31, 2014, approximately 94% of EGT's capacity was under contract with an average remaining contract life of 3.5 years. The primary terms of EGT's firm transportation and storage contracts with CenterPoint Energy will begin to expire in 2018, with the majority of the contracts expiring in 2021.

EGT established maximum rates for interstate transportation and storage services on its system as required by FERC, though EGT is authorized to enter into negotiated rate and discounted rate agreements with customers. In October 2012, we initiated a process with EGT's customers to reach an agreed-upon rate, or settlement rate, that will allow us to recover on the increased costs associated with maintaining a safe and reliable system. These discussions have been discontinued and EGT is under no obligation to initiate a rate proceeding by a date certain.

Storage. EGT's storage assets include two underground natural gas storage facilities in Oklahoma and one underground natural gas storage facility in Louisiana, which operate at a combined capacity of 31.5 Bcf with 774 MMcf/d of aggregate maximum withdrawal capacity as of December 31, 2014.

MRT

General. MRT is a 1,663-mile interstate pipeline that provides natural gas transportation and storage services principally in Texas, Arkansas, Louisiana, Missouri and Illinois. This system provides market access for producers from the Haynesville and Fayetteville Shale plays. The system could transport 1.9 Bcf/d of natural gas as of December 31, 2014. For the year ended December 31, 2014, we transported an average of approximately 0.8 TBtu/d on this system. The system has pipeline diameters ranging from two to 26 inches and has 17 compressor stations. The system also had 32.0 Bcf of working natural gas storage capacity as of December 31, 2014.

Delivery Points. MRT's primary delivery points are to LDCs and industrial markets in the St. Louis market area. MRT's shippers access natural gas at Perryville, Louisiana and East Texas markets and, via EGT interconnects, the Mid-Continent.

Customers. MRT derives a significant portion of its gross margin from an affiliate of Laclede, the local natural gas distribution company serving the St. Louis market area, which comprised 59% of MRT's gross margin for the year ended December 31, 2014. MRT's other customers include subsidiaries of Ameren, subsidiaries of CenterPoint Energy and other industrial companies. MRT's customers are primarily located in Arkansas, Illinois and Missouri.

Contracts. MRT's services to its customers are typically provided under firm storage and transportation agreements. For the year ended December 31, 2014, approximately 10% of total transportation and storage segment gross margins were derived from demand charges under MRT's firm contract arrangements. As of December 31, 2014, approximately 90% of MRT's capacity was

Table of Contents

under contract with an average remaining contract life of 3.7 years. MRT's firm transportation and storage contracts with Laclede were extended during 2014 and are scheduled to expire in 2017 and 2018.

Storage. MRT's storage assets include two underground natural gas storage facilities in Louisiana and one underground natural gas storage facility in Illinois, which operate at a combined capacity of 32.0 Bcf with 576 MMcf/d of aggregate maximum withdrawal capacity as of December 31, 2014.

Other Assets

SESH is a 286-mile interstate pipeline that provides natural gas transportation services. We own a 49.90% interest in SESH and operate the pipeline. We have the ability to acquire CenterPoint Energy's remaining 0.1% of SESH during 2015. Please read Item 13. "Certain Relationships and Related Party Transactions, and Director Independence—Transactions with CenterPoint Energy, OGE Energy and ArcLight—Acquisition of Remaining CenterPoint Energy Interest in SESH." The remaining 50% of SESH is owned by affiliates of Spectra Energy Corp, who are responsible for the pipeline's back office and marketing operations.

The SESH pipeline runs from Perryville, Louisiana, to southwestern Alabama near the Gulf Coast, where most of the gas transported by the pipeline is then transported by third-party pipelines to companies generating electricity for the Florida power market. As of December 31, 2014, the system could transport 1.6 Bcf/d of natural gas from Perryville to Gwinville, Mississippi, and 1.07 Bcf/d of natural gas to the pipeline's end point in Alabama. During the year ended December 31, 2014, an average of approximately 0.9 Bcf/d was transported on this system. The system has pipeline diameters ranging from 16 to 42 inches and has 3 compressor stations.

The SESH pipeline has 11 interconnections with existing natural gas pipelines and access to three high deliverability storage facilities: Mississippi Hub Storage, Petal Gas Storage and Southern Pines Energy Center.

The primary customers for the SESH pipeline are companies that generate electricity using natural gas in the Florida market area. The rates charged by SESH for interstate transportation services are regulated by FERC. Service on SESH is largely provided under long-term, negotiated rate agreements with customers.

Competition

Our interstate pipelines compete with other interstate and intrastate pipelines. The principal elements of competition among pipelines are rates, terms of service, and flexibility and reliability of service.

Table of Contents

Intrastate Transportation

General. Our intrastate pipelines consist of approximately 2,300 miles of intrastate transportation pipeline in Oklahoma with 1.61 TBtu/d of average daily throughput for the year ended December 31, 2014 and approximately 20 miles of intrastate transportation pipeline in Illinois. Our intrastate systems deliver natural gas from the Arkoma and Anadarko basins, including growth activity in the Cana Woodford, Granite Wash, Cleveland, Tonkawa, SCOOP and Mississippi Lime Shale plays in western Oklahoma and the Texas Panhandle, to interstate and intrastate pipelines and end users.

Delivery Points. Our intrastate pipelines are connected to our EGT system and 12 third-party natural gas pipelines and have 66 interconnect points. These third-party natural gas pipelines include ANR Pipeline, El Paso Natural Gas Pipeline, Gulf Crossing Pipeline Company LLC, MEP, Natural Gas Pipeline Company of America, Northern Natural Gas Company, ONEOK Gas Transmission, Ozark Gas Transmission, L.L.C., Panhandle Eastern Pipe Line, Postrock KPC Pipeline, LLC, Southern Star Central Gas Pipeline and Western Farmers Electric Cooperative. In addition, our intrastate pipelines are connected to 37 end-user customers, including 15 natural gas-fired electric generation facilities in Oklahoma.

Customers. Our major transportation customers are OG&E, our affiliate, and Public Service Company of Oklahoma, an affiliate of AEP (PSO), the two largest electric utilities in Oklahoma. We provide gas transmission delivery services to all of OG&E’s and PSO’s natural gas-fired electric generation facilities in Oklahoma under firm intrastate transportation contracts. Customer demand for natural gas on our system is usually greater during the summer, primarily due to demand by natural gas-fired electric generation facilities to serve residential and commercial electricity requirements.

Contracts. The intrastate pipelines provide fee-based firm and interruptible transportation services on both an intrastate basis and, pursuant to Section 311 of the NGPA, on an interstate basis. Transportation services are offered under Section 311 of the NGPA pursuant to terms and conditions specified in our statement of operating conditions for natural gas transportation. Our intrastate pipelines derive a substantial portion of gross margins from firm transportation services subject to reservation charges. To the extent pipeline capacity is not needed for such firm transportation services and contracted capacity, we offer interruptible transportation services.

For the year ended December 31, 2014, approximately 18% of our total transportation and storage segment gross margins were derived from demand charges under firm contract arrangements for our intrastate pipelines with an average remaining contract life of 3.9 years. Our contracts with PSO and OG&E provide for a monthly demand charge plus variable transportation charges including fuel. In December 2014, we entered into a new transportation agreement with PSO with a one-year term from January 1, 2015, through January 1, 2016. In March 2014, we entered into a new transportation agreement with OG&E with a primary

Table of Contents

term from May 1, 2014, through April 30, 2019, which will remain in effect following the primary term from year to year thereafter unless either party provides notice of termination to the other party at least 180 days prior to the commencement of the succeeding annual period.

Storage. Our intrastate storage assets include two underground natural gas storage facilities in Oklahoma, which operate at a combined capacity of 24 Bcf with 605 MMcf/d of aggregate maximum withdrawal capacity as of December 31, 2014.

Competition

Our intrastate pipeline system competes with numerous interstate and intrastate pipelines, including several of the interconnected pipelines discussed above, as well as other natural gas storage facilities. The principal elements of competition are rates, terms of services, flexibility and reliability of service. Natural gas-fired electric generation facilities contribute their highest value when they have the capability to provide load following service to the customer (i.e., the ability of the generation facility to regulate generation to respond to and meet the instantaneous changes in customer demand for electricity). While the physical characteristics of natural gas-fired electric generation facilities are known to provide quick start-up, on-line functionality and the ability to efficiently provide varying levels of electric generation relative to other forms of generation, a key part of their effectiveness is contingent upon having access to an integrated pipeline and storage system that can respond quickly to meet their corresponding fluctuating fuel needs.

Rate and Other Regulation

Federal, state, and local regulation of pipeline gathering and transportation services may affect certain aspects of our business and the market for our products and services.

Interstate Natural Gas Pipeline Regulation

Our interstate pipeline systems—EGT, MRT, and SESH—are subject to regulation by FERC under the NGA and are considered natural gas companies. Natural gas companies may not charge rates that have been determined to be unjust or unreasonable by FERC. In addition, FERC prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service. FERC authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce includes:

- rates, operating terms, conditions of service and service contracts;
- certification and construction of new facilities or expansion of existing facilities;
- extension or abandonment of services and facilities;
- maintenance of accounts and records;
- acquisition and disposition of facilities;
- initiation and discontinuation of services;
- depreciation and amortization policies;
- conduct and relationship with certain affiliates;
- market manipulation in connection with interstate natural gas sales, purchases or transportation; and
- various other matters.

Under the NGA, the rates for service on interstate facilities must be just and reasonable and not unduly discriminatory. Generally, the maximum filed recourse rates for interstate pipelines are based on the pipeline’s cost of service including recovery of and a return on the pipeline’s actual prudent investment cost. Key determinants in the ratemaking process are costs of providing service, allowed rate of return, volume throughput and contractual capacity commitment assumptions. Our interstate pipelines business operations may be affected by changes in the demand for natural gas, the available supply and relative price of natural gas in the Mid-continent and Gulf Coast natural gas supply regions and general economic conditions.

Tariff changes can only be implemented upon approval by FERC. Two primary methods are available for changing the rates, terms and conditions of service of an interstate natural gas pipeline. Under the first method, the pipeline voluntarily seeks a tariff change by making a tariff filing with FERC justifying the proposed tariff change and providing notice, generally 30 days, to the appropriate parties. FERC provides notice to the public through publication of the notice in the Federal Register. If FERC determines that a proposed change is just and reasonable, FERC accepts the proposed change and the pipeline will implement such a change in its tariff, normally 30 days after filing. However, if FERC determines that a proposed change may not be just and reasonable

Table of Contents

then FERC may suspend such a change for up to five months beyond the date on which the change would otherwise go into effect and set the matter for an administrative hearing. Subsequent to any suspension period ordered by FERC, the proposed change may be placed into effect by the company, pending final FERC approval. In most cases, a proposed rate increase is placed into effect before a final FERC determination on such rate increase, and the proposed increase is collected subject to refund (plus interest). Under the second method, FERC may, on its own motion or based on a complaint, initiate a proceeding seeking to compel the company to change its rates, terms and/or conditions of service. If FERC determines that the existing rates, terms and/or conditions of service are unjust, unreasonable, unduly discriminatory or preferential, then any rate reduction or change that it orders generally will be effective prospectively from the date of the FERC order requiring this change.

Market Behavior Rules; Posting and Reporting Requirements

On August 8, 2005, Congress enacted the EPAct of 2005. Among other matters, the EPAct of 2005 amended the NGA to add an anti-manipulation provision that makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulation to be prescribed by FERC and, furthermore, provides FERC with additional civil penalty authority. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provisions of the EPAct of 2005. The rules make it unlawful for any entity, directly or indirectly in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC or the purchase or sale of transportation services subject to the jurisdiction of FERC, to (1) use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The anti-manipulation rules apply to interstate gas pipelines and storage companies and intrastate gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted “in connection with” gas sales, purchases or transportation subject to FERC jurisdiction. The anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering to the extent such transactions do not have a “nexus” to jurisdictional transactions. The EPAct of 2005 also amends the NGA and the NGPA to give FERC authority to impose civil penalties for violations of these statutes and FERC’s regulations, rules, and orders, up to $1 million per day per violation for violations occurring after August 8, 2005. In connection with this enhanced civil penalty authority, FERC issued a revised policy statement on enforcement to provide guidance regarding the enforcement of the statutes, orders, rules and regulations it administers, including factors to be considered in determining the appropriate enforcement action to be taken. If we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. In addition, the CFTC is directed under the Commodities Exchange Act, or CEA, to prevent price manipulations for the commodity and futures markets, including the energy futures markets. Pursuant to the Dodd-Frank Act and other authority, the CFTC has adopted anti-market manipulation regulations that prohibit fraud and price manipulation in the commodity and futures markets. The CFTC also has statutory authority to seek civil penalties of up to the greater of $1 million or triple the monetary gain to the violator for violations of the anti-market manipulation sections of the CEA.

The EPAct of 2005 also added Section 23 to the NGA, authorizing FERC to facilitate price transparency in markets for the sale or transportation of physical natural gas in interstate commerce. In 2007, FERC took steps to enhance its market oversight and monitoring of the natural gas industry by issuing several rulemaking orders designed to promote gas price transparency and to prevent market manipulation. In December 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent order on rehearing, or Order No. 704. Order No. 704 requires buyers and sellers of annual quantities of natural gas of 2,200,000 MMBtu or more, including entities not otherwise subject to FERC’s jurisdiction, to provide by May 1 of each year an annual report to FERC describing their aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC's policy statement on price reporting. In June 2010, FERC issued the last of its three orders on rehearing and clarification further clarifying its requirements.

On November 15, 2012, the FERC issued a Notice of Inquiry seeking public comment on the issue of whether to amend its regulations under the natural gas market transparency provisions of Section 23 of the NGA, as adopted by EPAct of 2005, to consider the extent to which quarterly reporting of every natural gas transaction within FERC's NGA jurisdiction that entails physical delivery for the next day or next month would provide useful information for improving natural gas market transparency. On July 9, 2013, the FERC provided notice that it was making a data request of certain natural gas marketers to better assess the reporting requirements. FERC has not yet issued an order.

Intrastate Natural Gas Pipeline and Storage Regulation

Our transmission lines are subject to state regulation of rates and terms of service. In Oklahoma, our intrastate pipeline system is subject to regulation by the Oklahoma Corporation Commission, or the OCC. Oklahoma has a non-discriminatory access requirement, which is subject to a complaint-based review. In Illinois, our intrastate pipeline system is subject to regulation by the Illinois Commerce Commission.

Intrastate natural gas transportation is largely regulated by the state in which the transportation takes place. An intrastate natural gas pipeline system may transport natural gas in interstate commerce provided that the rates, terms, and conditions of such transportation service comply with FERC regulation and Section 311 of the NGPA and Part 284 of the FERC's regulations. The NGPA regulates, among other things, the provision of transportation and storage services by an intrastate natural gas pipeline on behalf of an interstate natural gas pipeline or a LDC served by an interstate natural gas pipeline. Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. The rates under Section 311 are maximum rates and we may negotiate contractual rates at or below such maximum rates. Rates for service pursuant to Section 311 of the NGPA are generally subject to review and approval by FERC at least once every five years. Should the FERC determine not to authorize rates equal to or greater than our currently approved Section 311 rates, our business may be adversely affected.
Failure to observe the service limitations applicable to transportation services provided under Section 311, failure to comply with the rates approved by FERC for Section 311 service, or failure to comply with the terms and conditions of service established in the pipeline's FERC-approved Statement of Operating Conditions could result in the assertion of federal NGA jurisdiction by FERC and/or the imposition of administrative, civil and criminal penalties, as described in the "—Interstate Natural Gas Pipeline Regulation" section above.

The transportation rates charged by Enable Oklahoma Intrastate Transmission, LLC for natural gas transportation in interstate commerce on intrastate pipelines are subject to the jurisdiction of FERC under Section 311 of the NGPA. Enable Oklahoma currently has two zones under its Section 311 transportation rate structure—an East Zone and a West Zone. Enable Oklahoma historically offered only interruptible Section 311 service in both zones. Enable Oklahoma began to offer firm Section 311 service in the East Zone on April 1, 2009 and in the West Zone on March 1, 2011. For Section 311 service, Enable Oklahoma may charge up to its maximum established zonal East and West interruptible transportation rates for interruptible transportation in one zone or cumulative maximum rates for transportation in both zones. Enable Oklahoma may charge up to its maximum established firm rate for firm Section 311 transportation in its East and West Zones. Finally, Enable Oklahoma may charge the applicable fixed zonal fuel percentage(s) for the fuel used in transporting natural gas under Section 311 on our system. The fuel percentages are the same for firm and interruptible Section 311 services.

We also have a pipeline in Illinois that is subject to regulation by the Illinois Commerce Commission as a "Hinshaw pipeline." Under Section 1(c) of the NGA, a Hinshaw pipeline is exempt from FERC's NGA regulation if its operations are within a single state, if any gas received from interstate sources is received within the state and if its service is regulated by the state commission. A Hinshaw pipeline may, and our Illinois pipeline does, provide services in interstate commerce pursuant to limited jurisdiction certificate authority under Section 284.224(c) of FERC's regulations, thereby subjecting itself to the same type of limited FERC jurisdiction imposed on intrastate pipelines engaged in Section 311 service.

In May 2010, FERC issued Order No. 735, which requires intrastate pipelines providing transportation services under Section 311 of the NGPA and Hinshaw pipelines operating under Section 1(c) of the NGA to report on a quarterly basis more detailed information and storage transaction information, including: rates charged by the pipeline under each contract; receipt and delivery points and zones or segments covered by each contract; the quantity of natural gas the shipper is entitled to transport, store, or deliver; the duration of the contract; and whether there is an affiliate relationship between the pipeline and the shipper. Order No. 735 further requires that such information must be supplied through a new electronic reporting system and will be posted on FERC's website, and that such quarterly reports may not contain information redacted as privileged. FERC promulgated this rule after determining that such transactional information would help shippers make more informed purchasing decisions and would improve the ability of both shippers and FERC to monitor actual transactions for evidence of market power or undue discrimination. Order No. 735 also extends FERC's periodic review of the rates charged by the subject pipelines from three to five years. Order No. 735 became effective on April 1, 2011. In December 2010, FERC issued Order No. 735-A. In Order No. 735-A, FERC generally reaffirmed Order No. 735 requiring Section 311 and "Hinshaw" pipelines to report on a quarterly basis storage and transportation transactions containing specific information for each transaction, aggregated by contract. Our intrastate storage assets at the Wetumka Storage Field offer both fee-based firm and interruptible storage services under Section 311 of the NGPA pursuant to terms and conditions specified in our statement of operating conditions for gas storage at market-based rates. Our intrastate Stuart Storage Field currently is used exclusively to provide intrastate storage service, even though FERC previously authorized the use of that storage facility for Section 311 interstate service.

Table of Contents

Natural Gas Gathering Pipeline Regulation

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC. Although the FERC has not made formal determinations with respect to all of our facilities we consider to be gathering facilities, management believes that our natural gas pipelines meet the traditional tests that the FERC has used to determine that a pipeline is a gathering pipeline and is therefore not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and the FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities is subject to change based on future determinations by the FERC, the courts or Congress. If the FERC were to consider the status of an individual facility and determine that the facility and/or services provided by it are not exempt from FERC regulation under the NGA and that the facility provides interstate service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by the FERC under the NGA or the NGPA. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect our results of operations and cash flows. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of civil penalties as well as a requirement to disgorge charges collected for such service in excess of the rate established by the FERC.
States may regulate gathering pipelines. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, requirements prohibiting undue discrimination, and in some instances complaint-based rate regulation. Our gathering operations may be subject to ratable take and common purchaser statutes in the states in which they operate. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

Oklahoma and Texas have each adopted a form of complaint-based regulation of gathering operations that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering open access and rate discrimination. Texas has also adopted a complaint based regulation, known as the lost and unaccounted for gas bill, which gives the Texas Railroad Commission the authority to issue orders for purposes of preventing waste in specific situations. To date, neither the gathering regulations nor the lost and unaccounted for gas bill have had a significant impact on our operations in Oklahoma or Texas. However, we cannot predict what effect, if any, either of these regulations might have on its gathering operations in Oklahoma or Texas in the future.

Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Our gathering operations could also be subject to additional safety and operational regulations relating to the design, construction, testing, operation, replacement and maintenance of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on its operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Sales of Natural Gas

The price at which we buy and sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. However, as noted above, with regard to our physical purchases and sales of these energy commodities, and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the CFTC. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations.

Table of Contents

Crude Oil Gathering Regulation

Crude oil gathering pipelines that provide interstate transportation service may be regulated as a common carrier by FERC under the ICA, the Energy Policy Act of 1992, and the rules and regulations promulgated under those laws. The ICA and FERC regulations require that rates for interstate service pipelines that transport crude oil and refined petroleum products (collectively referred to as “petroleum pipelines”) and certain other liquids, be just and reasonable and are to be non-discriminatory or not confer any undue preference upon any shipper. FERC regulations also require interstate common carrier petroleum pipelines to file with FERC and publicly post tariffs stating their interstate transportation rates and terms and conditions of service. Under the ICA, FERC or interested persons may challenge existing or changed rates or services. The FERC is authorized to investigate such charges and may suspend the effectiveness of a new rate for up to seven months. A successful rate challenge could result in a common carrier paying refunds together with interest for the period that the rate was in effect. FERC may also order a pipeline to change its rates, and may require a common carrier to pay shippers reparations for damages sustained for a period up to two years prior to the filing of a complaint.

If our rate levels were investigated by FERC, the inquiry could result in a comparison of our rates to those charged by others or to an investigation of our costs, including:
- the overall cost of service, including operating costs and overhead;
- the allocation of overhead and other administrative and general expenses to the regulated entity;
- the appropriate capital structure to be utilized in calculating rates;
- the appropriate rate of return on equity and interest rates on debt;
- the rate base, including the proper starting rate base;
- the throughput underlying the rate; and
- the proper allowance for federal and state income taxes.

For some time now, FERC has been issuing regulatory assurances that necessarily balance the anti-discrimination and undue preference requirements of common carriage with the expectations of investors in new and expanding petroleum pipelines. There is an inherent tension between the requirements imposed upon a common carrier and the need for owners of petroleum pipelines to be able to enter into long-term, firm contracts with shippers willing to make the commitments which underpin such large capital investments. For example, FERC has found that shipper contract rates are not per se violations of the duty of non-discrimination, provided that such rates are available to all similarly-situated shippers. In the same vein, FERC has approved varying term commitments with tiered rate discounts on the basis that committed shippers were not similarly situated with uncommitted shippers and further that different types of committed shippers were not similarly situated with each other if their commitment level materially differed. FERC has also found that shippers making certain commitments to the pipeline can take advantage of priority or firm service, which is service that is not subject to typical capacity allocation requirements, so long as any interested shipper has an equal opportunity to make such a commitment to the carrier. FERC’s solution has been to allow carriers to hold an “open season” prior to the in-service date of pipeline, during which time interested shippers can make commitments to the proposed pipeline project. Throughput commitments from interested shippers during an open season can be for firm service or for non-firm service. Typically, such an open season is for a 30-day period, must be publicly announced, and culminates in interested parties entering into transportation agreements with the carrier. Under FERC precedent, a carrier typically may reserve up to 90% of available capacity for the provision of firm service to shippers making a commitment. At least 10% of capacity ordinarily is reserved for “walk-up” shippers.

Under the ICA, FERC does not have authority over the siting of oil transportation assets nor over the abandonment of facilities or services. Accordingly, no approval from FERC is necessary prior to placing a new petroleum pipeline project in operation. However, FERC highly encourages carriers to file a Petition for Declaratory Order (PDO) to seek regulatory assurances for key terms of service offered during an open season. As long as the shippers on our Bakken crude oil gathering system move oil in interstate commerce, our crude oil gathering system will not be regulated by the North Dakota Public Service Commission.

Safety and Health Regulation

Certain of our facilities are subject to pipeline safety regulations. PHMSA regulates safety requirements in the design, construction, operation and maintenance of jurisdictional natural gas and hazardous liquid pipeline facilities. All natural gas transmission facilities, such as our interstate natural gas pipelines, are subject to PHMSA's pipeline safety regulations, but natural gas gathering pipelines are subject to the pipeline safety regulations only to the extent they are classified as regulated gathering pipelines. In addition, several NGL pipeline facilities and crude oil pipeline facilities are regulated as hazardous liquids pipelines.

Table of Contents

Currently, each such NGL or crude oil facility is excepted from many of the requirements of PHMSA's regulations applicable to hazardous liquids pipelines based on the facility's location, product transported, and/or the low stress level at which it operates.

Pursuant to the Natural Gas Pipeline Safety Act of 1968, or NGPSA, and the Hazardous Liquid Pipeline Safety Act of 1979, or HLPSA, as amended by the Pipeline Safety Act of 1992, or PSA, the Accountable Pipeline Safety and Partnership Act of 1996, or APSA, the Pipeline Safety Improvement Act of 2002, or PSIA, the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, or the PIPES Act, and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, or the 2011 Pipeline Safety Act, the DOT, through PHMSA, regulates pipeline safety and integrity. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities, while the PSIA establishes mandatory inspections for all U.S. oil and natural gas transmission pipelines in high-consequence areas, or HCAs.

NGL and crude oil pipelines are subject to regulation by PHMSA under the HLPSA which requires PHMSA to develop, prescribe, and enforce minimum federal safety standards for the transportation of hazardous liquids by pipeline, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of pipeline facilities. HLPSA covers petroleum and petroleum products, including NGLs and condensate, and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the United States Secretary of Transportation. These regulations include potential fines and penalties for violations. Management believes that we are in compliance in all material respects with these HLPSA regulations. The PSA added the environment to the list of statutory factors that must be considered in establishing safety standards for hazardous liquid pipelines, established safety standards for certain "regulated gathering lines," and mandated that regulations be issued to establish criteria for operators to use in identifying and inspecting pipelines located in HCAs, defined as those areas that are unusually sensitive to environmental damage, that cross a navigable waterway, or that have a high population density. In 1996, Congress enacted the APSA, which limited the operator identification requirement to operators of pipelines that cross a waterway where a substantial likelihood of commercial navigation exists, required that certain areas where a pipeline rupture would likely cause permanent or long-term environmental damage be considered in determining whether an area is unusually sensitive to environmental damage, and mandated that regulations be issued for the qualification and testing of certain pipeline personnel. In the PIPES Act, Congress required mandatory inspections for certain U.S. crude oil and natural gas transmission pipelines in HCAs and mandated that regulations be issued for low-stress hazardous liquid pipelines and pipeline control room management.

PHMSA has developed regulations that require natural gas pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in HCAs. The regulations require operators, including us, to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact an HCA;
- improve data collection, integration and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating actions.

Although many of our pipeline facilities fall within a class that is currently not subject to these integrity management requirements, we may incur significant costs and liabilities associated with repair, remediation, and preventive or mitigating measures associated with our non-exempt pipelines. In 2014, we incurred $29 million of capital expenditures and operating costs for pipeline integrity management. We currently estimate that we will incur capital expenditures and operating costs of between $425 million and $450 million from 2015 to 2019 in connection with pipeline integrity management to complete the testing required by existing DOT regulations and their state counterparts. The estimated capital expenditures and operating costs include our estimates for the assessment, remediation and prevention or other mitigation that may be determined to be necessary. At this time, we cannot predict the ultimate costs of our integrity management program and compliance with these regulations because those costs will depend on the number and extent of any repairs found to be necessary and the degree to which newly proposed pipeline safety regulations may apply to our pipeline systems. We will continue to assess, remediate and maintain the integrity of our pipelines. The results of these activities could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operations of our pipelines. Additionally, should we fail to comply with DOT or comparable state regulations, we could be subject to penalties and fines. If future DOT pipeline integrity management regulations were to require that we expand our integrity managements program to currently unregulated pipelines, including gathering lines, our costs associated with compliance may have a material effect on our operations.

The 2011 Pipeline Safety Act reauthorizes funding for federal pipeline safety programs, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines. The 2011 Pipeline Safety Act, among other

Table of Contents

things, increases the maximum civil penalty for pipeline safety violations and directs the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation and testing to confirm the material strength of pipe operating above 30% of specified minimum yield strength in HCAs. Effective October 25, 2013, PHMSA adopted new rules increasing the maximum administrative civil penalties for violations of the pipeline safety laws and regulations after January 3, 2012 to $0.2 million per violation per day, with a maximum of $2 million for a related series of violations. In 2011, PHMSA issued a final rule applying safety regulations to certain rural low-stress hazardous liquid pipelines that were not covered previously by some of its safety regulations. PHMSA also published advance notice of proposed rulemakings to solicit comments on the need for changes to its natural gas and liquid pipeline safety regulations, including changes to those rules that would apply to gathering lines and removal of an exemption for natural gas pipelines installed before 1970. In May 2012, PHMSA published an advisory bulletin stating that operators of gas and hazardous liquid pipeline facilities should verify records relating to operating specifications for maximum allowable operating pressure, MAOP, for gas pipelines and maximum operating pressure, or MOP, for hazardous liquid pipelines. For natural gas transmission pipelines located within Class 3 and Class 4 locations or in Class 1 and Class 2 locations in HCAs, PHMSA modified its annual report form to require operators to report the number of verified miles of pipeline on their systems. This report was due and filed in June 2013, and subsequently updated in March 2014. No MOP reporting requirements were imposed on operators of hazardous liquid pipeline for the 2012 calendar year reports. Our current practice is to continually monitor and update our records with respect to MAOP of our gas pipelines. Finally, in January 2015, PHMSA stated that it will propose natural gas pipeline safety standards in 2015 that are expected to lower methane emissions. Future PHMSA rulemakings and/or industry commitments could have a material impact on our operations.

While we cannot predict the outcome of legislative or regulatory initiatives, such legislative and regulatory changes could have a material effect on our operations, particularly through more stringent and comprehensive safety regulations (such as integrity management requirements) to pipelines and gathering lines not previously subject to such requirements. While we expect any legislative or regulatory changes will provide sufficient time to come into compliance with the new requirements, the costs associated with compliance may have a material effect on our operations.

States are preempted by federal law from imposing pipeline safety standards below the minimum federal standards established by DOT, but they may establish more rigorous standards for intrastate gas and hazardous liquids pipelines. State agencies may also assume responsibility for enforcing intrastate pipeline regulations as a cooperating agency. In practice, states vary considerably in their authority and capacity to address pipeline safety. In the state of Oklahoma, the OCC’s Transportation Division, acting through the Pipeline Safety Department, administers the OCC’s intrastate regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipeline. The OCC develops regulations and other approaches to assure safety in design, construction, testing, operation, maintenance and emergency response to pipeline facilities. The OCC derives its authority over intrastate pipeline operations through state statutes and certification agreements with the DOT. A similar regime for safety regulation is in place in Texas and is administered by the Texas Railroad Commission. Our natural gas transmission and DOT regulated gathering pipelines have ongoing inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

We have incorporated all existing requirements into our programs by the required regulatory deadlines, and are continually incorporating the new requirements into procedures and budgets. We expect to incur increasing regulatory compliance costs, based on the intensification of the regulatory environment and forecasted changes to regulations as outlined above. In addition to regulatory changes, costs may be incurred when there is an accidental release of a commodity transported by our system, or a regulatory inspection identifies a deficiency in our required programs.

In addition to these pipeline safety requirements, we are subject to a number of federal and state laws and regulations, including the Occupational Safety and Health Act of 1970 (OSHA) and comparable state statutes, whose purpose is to protect the safety and health of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the Federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. We have an internal program of inspection designed to monitor and enforce compliance with worker safety and health requirements. Management believes that we are in material compliance with all applicable laws and regulations relating to worker safety and health.

The Department of Homeland Security Appropriation Act of 2007 requires the Department of Homeland Security, or DHS, to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including

Table of Contents

oil and gas facilities that are deemed to present “high levels of security risk.” The DHS issued an interim final rule in April 2007 regarding risk-based performance standards to be attained pursuant to this act and, on November 20, 2007, further issued an Appendix A to the interim rules that establish chemicals of interest and their respective threshold quantities that will trigger compliance with these interim rules. Covered facilities that are determined by DHS to pose a high level of security risk will be required to prepare and submit Security Vulnerability Assessments and Site Security Plans as well as comply with other regulatory requirements, including those regarding inspections, audits, recordkeeping, and protection of chemical-terrorism vulnerability information.

While we are not currently subject to governmental standards for the protection of computer-based systems and technology from cyber threats and attacks, proposals to establish such standards are being considered by the U.S. Congress and by U.S. Executive Branch departments and agencies, including the Department of Homeland Security, and we may become subject to such standards in the future. We have systems in place to monitor and address the risk of cyber-security breaches in our business, operations and control environments. We routinely review and update those systems as the nature of that risk requires. We are not aware of any cyber-security breach affecting any of our business, operations or control environments. A significant cyber-attack could have a material effect on our operations and those of our customers.

Environmental Matters

General

Our activities are subject to stringent and complex federal, state and local laws and regulations governing environmental protection including the discharge of materials into the environment. These laws and regulations can restrict or impact our business activities in many ways, such as restricting the way we can handle or dispose of our wastes, requiring remedial action to mitigate pollution conditions that may be caused by our operations or that are attributable to former operations, regulating future construction activities to mitigate harm to threatened or endangered species, wetlands and migratory birds, and requiring the installation and operation of pollution control equipment. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Management believes that our operations are in material compliance with current federal, state and local environmental standards.

Environmental regulation can increase the cost of planning, design, initial installation and operation of our facilities and has the potential to restrict or delay our operations and development projects, particularly pipeline projects. Historically, our total expenditures for environmental control measures and for remediation have not been significant in relation to our consolidated financial position or results of operations. Management believes, however, that it is reasonably likely that the trend in environmental legislation and regulations will continue towards more restrictive standards. Compliance with these standards is expected to increase the cost of conducting business.

Our routine environmental expenses for 2014 for technical support, fees, sampling, testing and other similar items were approximately $11 million. Reciprocating internal combustion engines maximum achievable control technology (RICE MACT) and greenhouse gases (GHG) expenses for 2014 were approximately $2 million. Routine expenses for 2015 to 2017 are expected to average $11 million per year, and RICE MACT and GHG costs are expected to average $2 million per year over the same timeframe. Costs for incidental environmental activities, such as permitting as part capital projects and waste disposal, are included in routine capital and operating expenses. Management continues to evaluate our compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

Air

Our operations are subject to the federal Clean Air Act, as amended (CAA), and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including natural gas processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions (including greenhouse gas emissions as discussed below), obtain and strictly comply with air permits containing various emissions and operational limitations or install emission control equipment. We likely will be required to incur certain capital expenditures in the future for air pollution control equipment and technology in connection with obtaining and maintaining operating permits and approvals for air emissions.

Table of Contents

Climate Change

More stringent laws and regulations relating to climate change, methane and GHGs may be adopted in the future and could cause us to incur material expenses in complying with them. The United States Congress has, from time to time, considered adopting legislation to reduce emissions of GHGs, and there has been a wide-ranging policy debate, both nationally and internationally, regarding the impact of these gases and possible means for their regulation. Some of the proposals would require industrial sources to meet stringent new standards that would require substantial reductions in carbon emissions. Following a finding by the U.S. Environmental Protection Agency (EPA) that certain GHGs represent an endangerment to human health, the EPA adopted two sets of rules regulating GHG emissions under the Clean Air Act. One requires a reduction in emissions of GHGs from motor vehicles beginning January 2, 2011. The other regulates emissions of GHGs from certain large stationary sources under the Clean Air Act's Prevention of Significant Deterioration and Title V programs, commencing when the motor vehicle standards took effect on January 2, 2011. Also, the EPA adopted its "Mandatory Reporting of Greenhouse Gases Rule" that requires the annual calculation and reporting of GHG emissions from natural gas transmission, gathering, processing and distribution systems and electric distribution systems that emit 25,000 metric tons or more of CO2 equivalent per year. These additional reporting requirements began in 2012 and we are currently in compliance. These permitting and reporting requirements could lead to further regulation of GHGs by the EPA.

Although the adoption of new legislation is uncertain, action by the EPA to impose new standards and reporting requirements regarding GHG emissions continues. For example, on January 14, 2015, the EPA announced that it will issue a proposed rule in the summer of 2015 and a final rule in 2016 setting standards for methane and VOC emissions from new and modified oil and gas production sources and natural gas processing and transmission sources. As part of the same announcement, PHMSA stated that it will propose natural gas pipeline safety standards in 2015 that are expected to lower methane emissions. Furthermore, in December 2014, the EPA proposed changes to its GHG reporting rule that would require additional reporting from natural gas transmission pipelines.

Several states have passed laws, adopted regulations or undertaken regulatory initiatives to reduce the emission of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Oklahoma, Arkansas, Louisiana, Kansas, Missouri, Illinois, Tennessee, Mississippi, Alabama, North Dakota and Texas are not among them. If legislation or regulations are passed at the federal or state levels in the future requiring mandatory reductions of carbon dioxide, methane and other GHGs on our facilities, this could result in significant additional compliance costs that would affect the our future financial position, results of operations and cash flows.

The adoption of legislation or regulatory programs to reduce emissions of methane and GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions monitoring and control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the natural gas we gather, treat and transport. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations.

National Environmental Policy Act (NEPA)

NEPA provides for regulatory review in connection with certain projects that involve federal lands or require certain actions by federal agencies, which implicates a number of other laws and regulations such as the Endangered Species Act, Migratory Bird Treaty Act, Rivers and Harbors Act, Clean Water Act, Bald and Golden Eagle Protection Act, Fish and Wildlife Coordination Act, Marine Mammal Protection Act and National Historic Preservation Act. The NEPA review process can be lengthy and subjective and can cause delays in projects. Some of our projects that require NEPA review are related to pipeline integrity. Ineffective implementation of this process could cause significant impacts to commercial and compliance projects.

Endangered Species

Certain federal laws, including the Bald and Golden Eagle Protection Act, the Migratory Bird Treaty Act and the Endangered Species Act, provide special protection to certain designated species. These laws and any state equivalents provide for significant civil and criminal penalties for unpermitted activities that result in harm to or harassment of certain protected animals and plants, including damage to their habitats. If such species are located in an area in which we conduct operations, or if additional species in those areas become subject to protection, our operations and development projects, particularly pipeline projects, could be restricted or delayed, or we could be required to implement expensive mitigation measures. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the Endangered Species Act, or ESA, by no later than completion of the agency’s 2017 fiscal year. The designation of previously unprotected species as threatened

Table of Contents

or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our customer's exploration and production activities that could have an adverse impact on demand for our services. Portions of the basins we serve are designated as critical or suitable habitat for endangered species. If additional portions of the basins we serve were designated as critical or suitable habitat for endangered species, it could adversely impact the cost of operating our systems and of constructing new facilities. Management believes that we are in material compliance with all applicable laws providing special protection to designated species.

Hazardous Substances and Waste

Our operations are subject to federal and state environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes, and petroleum hydrocarbons. For instance, our operations are subject to the Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA or Superfund) and comparable state cleanup laws that impose liability, without regard to the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. These persons include current and prior owners or operators of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Because we utilize various products and generate wastes that are considered hazardous substances for purposes of CERCLA, we could be subject to liability for the costs of cleaning up and restoring sites where those substances have been released to the environment. At this time, it is not anticipated that any associated liability will cause a significant impact to us.

Our operations also generate solid and hazardous wastes that are subject to the federal Resource Conservation and Recovery Act of 1976 (RCRA) as well as comparable state laws. While RCRA regulates both solid and hazardous wastes, it imposes detailed requirements for the handling, storage, treatment and disposal of hazardous waste. RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. However, it is possible that these wastes, which could include wastes currently generated during our operations, will in the future be designated as "hazardous wastes" and therefore be subject to more rigorous and costly disposal requirements. Such changes to the law could have an impact on our capital expenditures and operating expenses. Further, these RCRA-exempt oil and gas exploration and production wastes may still be regulated under state law or RCRA's less stringent solid waste requirements. The transportation of natural gas in pipelines may also generate some hazardous wastes that are subject to RCRA or a comparable state law regime.

Water

Our operations are subject to the federal Clean Water Act and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into state and federal waters. The discharge of pollutants, including discharges resulting from a spill or leak, is prohibited unless authorized by a permit or other agency approval. In addition, the federal Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. These permits may require us to monitor and sample the storm water runoff from some of our facilities. The federal Clean Water Act and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon tank spill, rupture or leak. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with many of these requirements.

The primary federal law related to oil spill liability is the Oil Pollution Act (the OPA) which amends and augments oil spill provisions of the Clean Water Act and imposes certain duties and liabilities on certain “responsible parties” related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable “responsible party” includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge, or in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, we may be liable for costs and damages.

Table of Contents

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and a small percentage of chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is regulated by state agencies, typically the state’s oil and gas commission. A number of federal agencies, including the EPA and the U.S. Department of Energy, are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. In addition, some states have adopted, and other states are considering adopting, regulations that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for our customers to perform fracturing to stimulate production from tight formations. Restrictions on hydraulic fracturing could also reduce the volume of natural gas that our customers produce, and could thereby adversely affect our revenues and results of operations.

For a further discussion regarding contingencies relating to environmental laws and regulations, see Note 14 to Notes to Combined and Consolidated Financial Statements.

Impact of Seasonality

While the results of our gathering and processing segment are not materially affected by seasonality, from time to time our operations can be impacted by inclement weather. Our transportation and storage segment experiences seasonal impacts associated with storage spreads, basis spreads on market-based pipelines, power plant demand and local distribution company customer demand.

Employees

As of December 31, 2014, approximately 2,000 individuals were providing services to us as seconded employees by CenterPoint Energy and OGE Energy, and other individuals were providing services to us pursuant to services agreements with CenterPoint Energy or OGE Energy. We had 3 direct employees as of December 31, 2014. The Partnership transitioned seconded employees from CenterPoint Energy and OGE Energy to the Partnership effective January 1, 2015, except for those 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. As of January 1, 2015, we have approximately 1,800 employees, and approximately 200 individuals provide services to us as seconded employees from OGE Energy. Please read Item 13, "Certain Relationships and Related Party Transactions—Employee Agreements" for a description of the agreements governing these relationships.

Item 1A. Risk Factors

You should carefully consider each of the following risks and all of the other information contained in this Annual Report on Form 10-K in evaluating us and our common units. Some of these risks relate principally to our business and the industry in which we operate, while others relate principally to tax matters, ownership of our common units, and securities markets generally. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, we might not be able to pay the minimum quarterly distribution on our common units, or the trading price of our common units could decline.

Risks Related to Our Business

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner and its affiliates, to enable us to pay the minimum quarterly distribution to holders of our common and subordinated units.

We may not have sufficient available cash each quarter to enable us to pay the minimum quarterly distribution. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees and gross margins we realize with respect to the volume of natural gas and crude oil that we handle;

Table of Contents

- the prices of, levels of production of, and demand for natural gas and crude oil;
- the volume of natural gas and crude oil we gather, compress, treat, dehydrate, process, fractionate, transport and store;
- the relationship among prices for natural gas, NGLs and crude oil;
- cash calls and settlements of hedging positions;
- margin requirements on open price risk management assets and liabilities;
- the level of competition from other midstream energy companies;
- adverse effects of governmental and environmental regulation;
- the level of our operation and maintenance expenses and general and administrative costs; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, including:

- the level and timing of capital expenditures we make;
- the cost of acquisitions;
- our debt service requirements and other liabilities;
- fluctuations in working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our debt agreements;
- the amount of cash reserves established by our general partner; and
- other business risks affecting our cash levels.

Our contracts are subject to renewal risks.

We generate a substantial portion of our gross margins under long-term, fee-based agreements. For the year ended December 31, 2014, approximately 72% of our gross margin was generated from contracts that are fee-based and approximately 50% of our gross margin was attributable to fees associated with firm contracts or contracts with minimum volume commitment features. As these and other contracts expire, we may have to negotiate extensions or renewals with existing suppliers and customers or enter into new contracts with other suppliers and customers. We may be unable to obtain new contracts on favorable commercial terms, if at all. We also may be unable to maintain the economic structure of a particular contract with an existing customer or the overall mix of our contract portfolio. For example, depending on prevailing market conditions at the time of a contract renewal, gathering and processing customers with fixed-fee or fixed-margin contracts may desire to enter into contracts under different fee arrangements. To the extent we are unable to renew our existing contracts on terms that are favorable to us, if at all, or successfully manage our overall contract mix over time, our revenue, results of operations and distributable cash flow could be adversely affected.

We depend on a small number of customers for a significant portion of our firm transportation and storage services revenues. The loss of, or reduction in volumes from, these customers could result in a decline in sales of our transportation and storage services and our consolidated financial position, results of operations and our ability to make cash distributions to our unitholders.

We provide firm transportation and storage services to certain key customers on our system. Our major transportation customers are affiliates of CenterPoint Energy, Laclede, AEP, XTO and OGE Energy.

The loss of all or even a portion of the interstate or intrastate transportation and storage services for any of these customers, the failure to extend or replace these contracts or the extension or replacement of these contracts on less favorable terms, as a result of competition or otherwise, could adversely affect our combined and consolidated financial position, results of operations and our ability to make cash distributions to unitholders.

Our businesses are dependent, in part, on the drilling and production decisions of others.

Our businesses are dependent on the continued availability of natural gas and crude oil production. We have no control over the level of drilling activity in our areas of operation, the amount of reserves associated with wells connected to our systems or the rate at which production from a well declines. In addition, our cash flows associated with wells currently connected to our systems will decline over time. To maintain or increase throughput levels on our gathering and transportation systems and the asset utilization rates at our natural gas processing plants, our customers must continually obtain new natural gas and crude oil

Table of Contents

supplies. The primary factors affecting our ability to obtain new supplies of natural gas and crude oil and attract new customers to our assets are the level of successful drilling activity near these systems, our ability to compete for volumes from successful new wells and our ability to expand capacity as needed. If we are not able to obtain new supplies of natural gas and crude oil to replace the natural decline in volumes from existing wells, throughput on our gathering, processing, transportation and storage facilities would decline, which could have a material adverse effect on our results of operations and distributable cash flow. We have no control over producers or their drilling and production decisions, which are affected by, among other things:

- the availability and cost of capital;
- prevailing and projected commodity prices, including the prices of natural gas, NGLs and crude oil;
- demand for natural gas, NGLs and crude oil;
- levels of reserves;
- geological considerations;
- environmental or other governmental regulations, including the availability of drilling permits and the regulation of hydraulic fracturing; and
- the availability of drilling rigs and other costs of production and equipment.

Fluctuations in energy prices can also greatly affect the development of new natural gas and crude oil reserves. Drilling and production activity generally decreases as commodity prices decrease. In general terms, the prices of natural gas, crude oil and other hydrocarbon products fluctuate in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control. Because of these factors, even if new natural gas or crude oil reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. Declines in natural gas or crude oil prices can have a negative impact on exploration, development and production activity and, if sustained, could lead to decreases in such activity. A sustained decline could also lead producers to shut in production from their existing wells. Sustained reductions in exploration or production activity in our areas of operation could lead to further reductions in the utilization of our systems, which could have a material adverse effect on our business, financial condition, results of operations and ability to make quarterly cash distributions to our unitholders.

In addition, it may be more difficult to maintain or increase the current volumes on our gathering systems, as several of the formations in the unconventional resource plays in which we operate generally have higher initial production rates and steeper production decline curves than wells in more conventional basins. Should we determine that the economics of our gathering assets do not justify the capital expenditures needed to grow or maintain volumes associated therewith, we may reduce such capital expenditures, which could cause revenues associated with these assets to decline over time. In addition to capital expenditures to support growth, the steeper production decline curves associated with unconventional resource plays may require us to incur higher maintenance capital expenditures relative to throughput over time, which will reduce our distributable cash flow.

Because of these and other factors, even if new reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. Reductions in drilling activity would result in our inability to maintain the current levels of throughput on our systems and could have a material adverse effect on our results of operations and distributable cash flow.

Our industry is highly competitive, and increased competitive pressure could adversely affect our results of operations and distributable cash flow.

We compete with similar enterprises in our respective areas of operation. The principal elements of competition are rates, terms of service and flexibility and reliability of service. Our competitors include large crude oil, natural gas and petrochemical companies that have greater financial resources and access to supplies of natural gas, NGLs and crude oil than us. Some of these competitors may expand or construct gathering, processing, transportation and storage systems that would create additional competition for the services we provide to our customers. Excess pipeline capacity in the regions served by our interstate pipelines could also increase competition and adversely impact our ability to renew or enter into new contracts with respect to our available capacity when existing contracts expire. In addition, our customers that are significant producers of natural gas may develop their own gathering, processing, transportation and storage systems in lieu of using ours. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of our competitors and customers. Further, natural gas utilized as a fuel competes with other forms of energy available to end-users, including electricity, coal and liquid fuels. Increased demand for such forms of energy at the expense of natural gas could lead to a reduction in demand for natural gas gathering, processing, transportation and transportation services. All of these competitive pressures could adversely affect our results of operations and distributable cash flow.

We derive a substantial portion of our operating income and cash flow from subsidiaries through which we hold a substantial portion of our assets.

We derive a substantial portion of our operating income and cash flow from, and hold a substantial portion of our assets through, our subsidiaries. As a result, we depend on distributions from our subsidiaries in order to meet our payment obligations. In general, these subsidiaries are separate and distinct legal entities and have no obligation to provide us with funds for our payment obligations, whether by dividends, distributions, loans or otherwise. In addition, provisions of applicable law, such as those limiting the legal sources of dividends, limit our subsidiaries' ability to make payments or other distributions to us, and our subsidiaries could agree to contractual restrictions on their ability to make distributions.

Our right to receive any assets of any subsidiary, and therefore the right of our creditors to participate in those assets, will be effectively subordinated to the claims of that subsidiary's creditors, including trade creditors. In addition, even if we were a creditor of any subsidiary, our rights as a creditor would be subordinated to any security interest in the assets of that subsidiary and any indebtedness of the subsidiary senior to that held by us.

The amount of cash we have available for distribution to holders of our common and subordinated units depends primarily on our cash flow rather than on our profitability, which may prevent us from making distributions, even during periods in which we record net income.

The amount of cash we have available for distribution depends primarily upon our cash flows and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

We may not be able to recover the costs of our substantial planned investment in capital improvements and additions, and the actual cost of such improvements and additions may be significantly higher than we anticipate.

Our business plan calls for extensive investment in capital improvements and additions. We estimate that our expansion capital expenditures could range from approximately $600 million to $800 million for the year ending December 31, 2015, not including opportunities currently under evaluation which could add up to an additional $300 million of expansion capital expenditures. For example, we are currently constructing two cryogenic processing facilities that we plan to connect to our super-header system in Grady County, Oklahoma, which are expected to add 400 MMcf/d of natural gas processing capacity. The first of the two new plants (the Bradley Plant) is expected to be completed in the first quarter of 2015. The second plant (the Grady County Plant) is a 200 MMcf/d plant that is expected to be completed in the first quarter of 2016. We also plan to construct significant natural gas gathering and compression infrastructure to support producer activity in our growth areas, and we anticipate that in 2015 we will complete the construction of our two crude gathering systems in North Dakota's Bakken Shale formation with a combined capacity of 49,500 Bbl/d.

The construction of additions or modifications to our existing systems, and the construction of new midstream assets, involves numerous regulatory, environmental, political and legal uncertainties, many of which are beyond our control and may require the expenditure of significant amounts of capital, which may exceed our estimates. These projects may not be completed at the planned cost, on schedule or at all. The construction of new pipeline, gathering, treating, processing, compression or other facilities is subject to construction cost overruns due to labor costs, costs of equipment and materials such as steel, labor shortages or weather or other delays, inflation or other factors, which could be material. In addition, the construction of these facilities is typically subject to the receipt of approvals and permits from various regulatory agencies. Those agencies may not approve the projects in a timely manner, if at all, or may impose restrictions or conditions on the projects that could potentially prevent a project from proceeding, lengthen its expected completion schedule and/or increase its anticipated cost. Moreover, our revenues and cash flows may not increase immediately upon the expenditure of funds on a particular project. For instance, if we expand an existing pipeline or construct a new pipeline, the construction may occur over an extended period of time, and we may not receive any material increases in revenues or cash flows until the project is completed. In addition, we may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. As a result, the new facilities may not be able to achieve our expected investment return, which could adversely affect our results of operations and our ability to make cash distributions to unitholders.

In connection with our capital investments, we may engage a third party to estimate potential reserves in areas to be developed prior to constructing facilities in those areas. To the extent we rely on estimates of future production in deciding to construct additions to our systems, those estimates may prove to be inaccurate due to numerous uncertainties inherent in estimating future production. As a result, new facilities may not be able to attract sufficient throughput to achieve expected investment return, which could adversely affect our results of operations and our ability to make cash distributions to unitholders. In addition, the construction

Table of Contents

of additions to existing gathering and transportation assets may require new rights-of-way prior to construction. Those rights-of-way to connect new natural gas supplies to existing gathering lines may be unavailable and we may not be able to capitalize on attractive expansion opportunities. Additionally, it may become more expensive to obtain new rights-of-way or to renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, our results of operations and our ability to make cash distributions to unitholders could be adversely affected.

Natural gas, NGL and crude oil prices are volatile, and changes in these prices could adversely affect our results of operations and our ability to make cash distributions to unitholders.

Our results of operations and our ability to make cash distributions to unitholders could be negatively affected by adverse movements in the prices of natural gas, NGLs and crude oil depending on factors that are beyond our control. These factors include demand for these commodities, which fluctuates with changes in market and economic conditions and other factors, including the impact of seasonality and weather, general economic conditions, the level of domestic and offshore natural gas production and consumption, the availability of imported natural gas, LNG, NGLs and crude oil, actions taken by foreign natural gas and oil producing nations, the availability of local, intrastate and interstate transportation systems, the availability and marketing of competitive fuels, the impact of energy conservation efforts, technological advances affecting energy consumption and the extent of governmental regulation and taxation.

Our keep-whole natural gas processing arrangements, which accounted for 7% of our natural gas processed volumes in 2014, expose us to fluctuations in the pricing spreads between NGL prices and natural gas prices. Under these arrangements, the processor processes raw natural gas to extract NGLs and pays to the producer the natural gas equivalent Btu value of raw natural gas received from the producer in the form of either processed natural gas or its cash equivalent. The processor is generally entitled to retain the processed NGLs and to sell them for its own account. Accordingly, the processor's margin is a function of the difference between the value of the NGLs produced and the cost of the processed natural gas used to replace the natural gas equivalent Btu value of those NGLs. Therefore, if natural gas prices increase and NGL prices do not increase by a corresponding amount, the processor has to replace the Btu of natural gas at higher prices and processing margins are negatively affected.

Our percent-of-proceeds and percent-of-liquids natural gas processing agreements accounted for 44% of our natural gas processed volumes in 2014. Under these arrangements, the processor generally gathers raw natural gas from producers at the wellhead, transports the natural gas through its gathering system, processes the natural gas and sells the processed natural gas and/or NGLs at prices based on published index prices. The price paid to producers is based on an agreed percentage of the actual proceeds of the sale of processed natural gas, NGLs or both, or the expected proceeds based on an index price. We refer to contracts in which the processor shares in specified percentages of the proceeds from the sale of natural gas and NGLs as "percent-of-proceeds" arrangements, and contracts in which the processor receives proceeds from the sale of a percentage of the NGLs or the NGLs themselves as compensation for processing services as "percent-of-liquids" arrangements. These arrangements expose us to risks associated with the price of natural gas and NGLs.

At any given time, our overall portfolio of processing contracts may reflect a net short position in natural gas (meaning that we are a net buyer of natural gas) and a net long position in NGLs (meaning that we are a net seller of NGLs). As a result, our gross margin could be adversely impacted to the extent the price of NGLs decreases in relation to the price of natural gas.

We have limited experience in the crude oil gathering business.

In November 2013, we commenced operations on our initial crude oil gathering pipeline system, located in Dunn and McKenzie Counties in North Dakota within the Bakken Shale formation. Additionally in February 2014, we executed a crude oil gathering agreement to gather crude oil production through a new system in Williams and Mountrail Counties in North Dakota that is expected to commence operations in the first quarter of 2015. These facilities, with a combined capacity of 49,500 barrels per day, are the first crude oil gathering systems that we have built and operated. Other operators of gathering systems in the Bakken Shale formation may have more experience in the construction, operation and maintenance of crude oil gathering systems than we do. This relative lack of experience may hinder our ability to fully implement our business plan in a timely and cost efficient manner, which, in turn, may adversely affect our results of operations and our ability to make cash distributions to unitholders.

We provide certain transportation and storage services under long-term, fixed-price “negotiated rate” contracts that are not subject to adjustment, even if our cost to perform such services exceeds the revenues received from such contracts, and, as a result, our costs could exceed our revenues received under such contracts.

We have been authorized by the Federal Energy Regulatory Commission, or FERC, to provide transportation and storage services at our facilities at negotiated rates. Generally, negotiated rates are in excess of the maximum recourse rates allowed by

Table of Contents

FERC, but it is possible that costs to perform services under “negotiated rate” contracts will exceed the revenues obtained under these agreements. If this occurs, it could decrease the cash flow realized by our systems and, therefore, decrease the cash we have available for distribution to our unitholders.

As of December 31, 2014, approximately 56% of our contracted transportation firm capacity and 44% of our contracted storage firm capacity was subscribed under such “negotiated rate” contracts. These contracts generally do not include provisions allowing for adjustment for increased costs due to inflation, pipeline safety activities or other factors that are not tied to an applicable tracking mechanism authorized by FERC. Successful recovery of any shortfall of revenue, representing the difference between “recourse rates” (if higher) and negotiated rates, is not assured under current FERC policies.

If third-party pipelines and other facilities interconnected to our gathering, processing or transportation facilities become partially or fully unavailable to us for any reason, our results of operations and our ability to make cash distributions to unitholders could be adversely affected.

We depend upon third-party natural gas pipelines to deliver natural gas to, and take natural gas from, our transportation systems. We also depend on third-party facilities to transport and fractionate NGLs that are delivered to the third party at the tailgates of the processing plants. Fractionation is the separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale. For example, an outage or disruption on certain pipelines or fractionators operated by a third party could result in the shutdown of certain of our processing plants, and a prolonged outage or disruption could ultimately result in a reduction in the volume of NGLs we are able to produce. Additionally, we depend on third parties to provide electricity for compression at many of our facilities. Since we do not own or operate any of these third-party pipelines or other facilities, their continuing operation is not within our control. If any of these third-party pipelines or other facilities become partially or fully unavailable to us for any reason, our results of operations and our ability to make cash distributions to unitholders could be adversely affected.

We do not own all of the land on which our pipelines and facilities are located, which could disrupt our operations.

We do not own all of the land on which our pipelines and facilities have been constructed, and we are therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way or if such rights-of-way lapse or terminate. We may obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for a specific period of time. A loss of these rights, through our inability to renew right-of-way contracts or otherwise, could cause us to cease operations temporarily or permanently on the affected land, increase costs related to the construction and continuing operations elsewhere, and adversely affect our results of operations and our ability to make cash distributions to unitholders.

We conduct a portion of our operations through joint ventures, which subject us to additional risks that could have a material adverse effect on the success of these operations, our financial position and our results of operations.

We conduct a portion of our operations through joint ventures with third parties, including affiliates of Spectra Energy Corp, DCP Midstream Partners, LP, Trans Louisiana Gas Pipeline, Inc. and Pablo Gathering LLC. We may also enter into other joint venture arrangements in the future. These third parties may have obligations that are important to the success of the joint venture, such as the obligation to pay their share of capital and other costs of the joint venture. The performance of these third-party obligations, including the ability of the third parties to satisfy their obligations under these arrangements, is outside our control. If these parties do not satisfy their obligations under these arrangements, our business may be adversely affected.

Our joint venture arrangements may involve risks not otherwise present when operating assets directly, including, for example:

- our joint venture partners may share certain approval rights over major decisions;
- our joint venture partners may not pay their share of the joint venture's obligations, leaving us liable for their shares of joint venture liabilities;
- we may be unable to control the amount of cash we will receive from the joint venture;
- we may incur liabilities as a result of an action taken by our joint venture partners;
- we may be required to devote significant management time to the requirements of and matters relating to the joint ventures;
- our insurance policies may not fully cover loss or damage incurred by both us and our joint venture partners in certain circumstances;

Table of Contents

- our joint venture partners may be in a position to take actions contrary to our instructions or requests or contrary to our policies or objectives; and
- disputes between us and our joint venture partners may result in delays, litigation or operational impasses.

The risks described above or the failure to continue our joint ventures or to resolve disagreements with our joint venture partners could adversely affect our ability to transact the business that is the subject of such joint venture, which would in turn negatively affect our financial condition and results of operations. The agreements under which we formed certain joint ventures may subject us to various risks, limit the actions we may take with respect to the assets subject to the joint venture and require us to grant rights to our joint venture partners that could limit our ability to benefit fully from future positive developments. Some joint ventures require us to make significant capital expenditures. If we do not timely meet our financial commitments or otherwise do not comply with our joint venture agreements, our rights to participate, exercise operator rights or otherwise influence or benefit from the joint venture may be adversely affected. Certain of our joint venture partners may have substantially greater financial resources than we have and we may not be able to secure the funding necessary to participate in operations our joint venture partners propose, thereby reducing our ability to benefit from the joint venture.

Under certain circumstances, affiliates of Spectra Energy Corp will have the right to purchase an ownership interest in SESH at fair market value.

We own a 49.90% ownership interest in SESH. The remaining 0.1% and 50.0% ownership interests are held by affiliates of CenterPoint Energy and Spectra Energy Corp, respectively. Under the master formation agreement, CenterPoint Energy has certain put rights, and we have certain call rights, exercisable with respect to the interest in SESH retained by CenterPoint Energy, under which CenterPoint Energy would contribute to us its interest in SESH at a price equal to the fair market value of the interest at the time the put right or call right is exercised. Please read Item 13. “Certain Relationships and Related Party Transactions—Transactions with CenterPoint Energy, OGE Energy and ArcLight—Acquisition of Remaining CenterPoint Energy Interest in SESH.”

CenterPoint Energy owns a 55.4% limited partner interest in us and a 40% economic interest in our general partner. Pursuant to the terms of the limited liability company agreement of SESH, as amended (the SESH LLC Agreement), if, at any time, CenterPoint Energy has a right to receive less than 50% of our distributions through its limited partner interest in us and its economic interest in our general partner, affiliates of Spectra Energy Corp will have the right to purchase our interest in SESH at fair market value. Affiliates of Spectra Energy Corp will also have a preferential purchase right with respect to any interest in SESH transferred to us by CenterPoint Energy if, at the time such interest is transferred, we are not an “affiliate” of CenterPoint Energy, as such term is defined in the SESH LLC Agreement. Under the master formation agreement, we are entitled to receive the cash consideration related to any exercise of these rights by Spectra Energy Corp or its affiliates.

An impairment of goodwill, long-lived assets, including intangible assets, and equity method investments could reduce our earnings.

In connection with our acquisition of Enogex, Waskom and other acquisitions prior to our formation, we have recorded goodwill and identifiable intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. GAAP requires us to test goodwill and intangible assets with indefinite useful lives for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets, including intangible assets with finite useful lives, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. For the investments we account for under the equity method, the impairment test considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. If we determine that an impairment is indicated, we would be required to take an immediate non-cash charge to earnings with a correlative effect on equity and balance sheet leverage as measured by debt to total capitalization. We recorded an impairment charge of $8 million, during the year ended December 31, 2014, of which $7 million was related to the Service Star business line. We could experience future events that result in impairments. An impairment of the value of our existing goodwill and intangible assets could have a significant negative impact on our future operating results and could have an adverse impact on our ability to satisfy the financial ratios or other covenants under our existing or future debt agreements.

Table of Contents

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. Insufficient insurance coverage and increased insurance costs could adversely impact our results of operations and our ability to make cash distributions to unitholders.

Our operations are subject to all of the risks and hazards inherent in the gathering, processing, transportation and storage of natural gas and crude oil, including:

- damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters, acts of terrorism and actions by third parties;
- inadvertent damage from construction, vehicles, farm and utility equipment;
- leaks of natural gas, crude oil and other hydrocarbons or losses of natural gas and crude oil as a result of the malfunction of equipment or facilities;
- ruptures, fires and explosions; and
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property, plant and equipment and pollution or other environmental damage. These risks may also result in curtailment or suspension of our operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations. We are not fully insured against all risks inherent in our business. We currently have general liability and property insurance in place to cover certain of our facilities in amounts that we consider appropriate. Such policies are subject to certain limits and deductibles. We do not have business interruption insurance coverage for all of our operations. Insurance coverage may not be available in the future at current costs or on commercially reasonable terms, and the insurance proceeds received for any loss of, or any damage to, any of our facilities may not be sufficient to restore the loss or damage without negative impact on our results of operations and our ability to make cash distributions to unitholders.

The use of derivative contracts by us and our subsidiaries in the normal course of business could result in financial losses that could negatively impact our results of operations and our ability to make cash distributions to unitholders.

We and our subsidiaries periodically use derivative instruments, such as swaps, options, futures and forwards, to manage our commodity and financial market risks. We and our subsidiaries could recognize financial losses as a result of volatility in the market values of these contracts, or should a counterparty fail to perform. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management’s judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

Failure to attract and retain an appropriately qualified workforce could adversely impact our results of operations.

We transitioned seconded employees from CenterPoint Energy and OGE Energy to the Partnership effective January 1, 2015, except for those 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. Employees of OGE Energy that we determine to hire are under no obligation to accept our offer of employment on the terms we provide, or at all.

Our business is dependent on our ability to recruit, retain and motivate employees. Certain circumstances, such as an aging workforce without appropriate replacements, a mismatch of existing skill sets to future needs, competition for skilled labor or the unavailability of contract resources may lead to operating challenges such as a lack of resources, loss of knowledge or a lengthy time period associated with skill development. Our costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect our ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, our results of operations could be negatively affected.

Our ability to grow is dependent on our ability to access external financing sources.

Our operating subsidiaries distribute all of their available cash to us and we distribute all of our available cash to our unitholders. As a result, we and our operating subsidiaries rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund acquisitions and expansion capital expenditures. As a result, to the extent we or our operating subsidiaries are unable to finance growth externally, our and our operating subsidiaries' cash distribution policy will significantly impair our and our operating subsidiaries' ability to grow. In addition, because we and

Table of Contents

our operating subsidiaries distribute all available cash, our and our operating subsidiaries' growth may not be as fast as businesses that reinvest their available cash to expand ongoing operations.

To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level, which in turn may impact the available cash that we have to distribute on each unit. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt by us or our operating subsidiaries to finance our growth strategy would result in increased interest expense, which in turn may negatively impact the available cash that our operating subsidiaries have to distribute to us, and that we have to distribute to our unitholders.

If we do not make acquisitions or are unable to make acquisitions on economically acceptable terms, our future growth will be adversely affected.

Our growth strategy includes, in part, the ability to make acquisitions that result in an increase in our cash generated from operations. If we are unable to make these accretive acquisitions either because: (i) we are unable to identify attractive acquisition targets or we are unable to negotiate purchase contracts on acceptable terms, (ii) we are unable to obtain acquisition financing on economically acceptable terms, or (iii) we are outbid by competitors, then our future growth and ability to increase distributions will be adversely affected.

Our merger and acquisition activities may not be successful or may result in completed acquisitions that do not perform as anticipated.

From time to time, we have made, and we intend to continue to make, acquisitions of businesses and assets. Such acquisitions involve substantial risks, including the following:

- acquired businesses or assets may not produce revenues, earnings or cash flow at anticipated levels;
- acquired businesses or assets could have environmental, permitting or other problems for which contractual protections prove inadequate;
- we may assume liabilities that were not disclosed to us, that exceed our estimates, or for which our rights to indemnification from the seller are limited;
- we may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems; and
- acquisitions, or the pursuit of acquisitions, could disrupt our ongoing businesses, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures.

Our and our operating subsidiaries' debt levels may limit our and their flexibility in obtaining additional financing and in pursuing other business opportunities.

As of December 31, 2014, we had approximately $1.9 billion of long-term debt outstanding, excluding the premiums on senior notes. We have $363 million of long-term notes payable-affiliated companies due to CenterPoint Energy. We have a $1.4 billion Revolving Credit Facility for working capital, capital expenditures and other partnership purposes, including acquisitions, of which $1.1 billion was available as of December 31, 2014. As of January 31, 2015, we had the ability to issue up to $1.2 billion in commercial paper, subject to available borrowing capacity under our Revolving Credit Facility and market conditions, to manage the timing of cash flows and fund short-term working capital deficits. As of January 31, 2015, $224 million was outstanding under our commercial paper program. We have the ability to incur additional debt, subject to limitations in our credit facilities. The levels of our debt could have important consequences, including the following:

- the ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or the financing may not be available on favorable terms, if at all;
- a portion of cash flows will be required to make interest payments on the debt, reducing the funds that would otherwise be available for operations, future business opportunities and distributions;
- our debt level will make us more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our debt level may limit our flexibility in responding to changing business and economic conditions.

Table of Contents

Our and our operating subsidiaries' ability to service our and their debt will depend upon, among other things, their future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our and their control. If operating results are not sufficient to service our or our operating subsidiaries' current or future indebtedness, we and they may be forced to take actions such as reducing distributions, reducing or delaying business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing debt, or seeking additional equity capital. These actions may not be effected on satisfactory terms, or at all. Please see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Our credit facilities contain operating and financial restrictions, including covenants and restrictions that may be affected by events beyond our control, which could adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Our credit facilities contain customary covenants that, among other things, limit our ability to:
- permit our subsidiaries to incur or guarantee additional debt;
- incur or permit to exist certain liens on assets;
- dispose of assets;
- merge or consolidate with another company or engage in a change of control;
- enter into transactions with affiliates on non-arm's length terms; and
- change the nature of our business.

Our credit facilities also require us to maintain certain financial ratios. Our ability to meet those financial ratios can be affected by events beyond our control, and we cannot assure you that we will meet those ratios. In addition, our credit facilities contain events of default customary for agreements of this nature.
Our ability to comply with the covenants and restrictions contained in our credit facilities may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any of the restrictions, covenants, ratios or tests in our credit facilities, a significant portion of our indebtedness may become immediately due and payable. In addition, our lenders' commitments to make further loans to us under the Revolving Credit Facility may be suspended or terminated. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. Please see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Affiliates of our general partner, including CenterPoint Energy and OGE Energy, may compete with us, and neither our general partner nor its affiliates have any obligation to present business opportunities to us.

Under our omnibus agreement, CenterPoint Energy, OGE Energy and their affiliates have agreed to hold or otherwise conduct all of their respective midstream operations located within the United States through us. This requirement will cease to apply to both CenterPoint Energy and OGE Energy as soon as either CenterPoint Energy or OGE Energy ceases to hold any interest in our general partner or at least 20% of our common units. In addition, if CenterPoint Energy or OGE Energy acquires any assets or equity of any person engaged in midstream operations with a value in excess of $50 million (or $100 million in the aggregate with such party's other acquired midstream operations that have not been offered to us), the acquiring party will be required to offer to us such assets or equity for such value. If we do not purchase such assets, the acquiring party will be free to retain and operate such midstream assets, so long as the value of the assets does not reach certain thresholds.

As a result, under the circumstances described above, CenterPoint Energy and OGE Energy have the ability to construct or acquire assets that directly compete with our assets. Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including its executive officers and directors and CenterPoint Energy and OGE Energy. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and our common unitholders.

Table of Contents

If our general partner fails to develop or maintain an effective system of internal controls, then we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our common units.

Our general partner has sole responsibility for conducting our business and for managing our operations. Effective internal controls are necessary for our general partner, on our behalf, to provide reliable financial reports, prevent fraud and operate us successfully as a public company. If our general partner's efforts to maintain its internal controls are not successful, it is unable to maintain adequate controls over our financial processes and reporting in the future or it is unable to assist us in complying with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002, our operating results could be harmed or we may fail to meet our reporting obligations. Ineffective internal controls also could cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our common units.

Cyber-attacks, acts of terrorism or other disruptions could adversely impact our results of operations and our ability to make cash distributions to unitholders.

We are subject to cyber-security risks related to breaches in the systems and technology that we use (i) to manage our operations and other business processes and (ii) to protect sensitive information maintained in the normal course of our businesses. The gathering, processing and transportation of natural gas from our gathering, processing and pipeline facilities are dependent on communications among our facilities and with third-party systems that may be delivering natural gas into or receiving natural gas and other products from our facilities. Disruption of those communications, whether caused by physical disruption such as storms or other natural phenomena, by failure of equipment or technology, or by manmade events, such as cyber-attacks or acts of terrorism, may disrupt our ability to deliver natural gas and control these assets. Cyber-attacks could also result in the loss of confidential or proprietary data or security breaches of other information technology systems that could disrupt our operations and critical business functions, adversely affect our reputation, and subject us to possible legal claims and liability. We are not fully insured against all cyber-security risks any of which could have a material adverse effect on our results of operations and our ability to make cash distributions to unitholders. In addition, our natural gas pipeline systems may be targets of terrorist activities that could disrupt our ability to conduct our business and have a material adverse effect on our results of operations and our ability to make cash distributions to unitholders. It is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations.

We may be unable to obtain or renew permits necessary for our operations, which could inhibit our ability to do business.

Performance of our operations require that we obtain and maintain a number of federal and state permits, licenses and approvals with terms and conditions containing a significant number of prescriptive limits and performance standards in order to operate. All of these permits, licenses, approval limits and standards require a significant amount of monitoring, record keeping and reporting in order to demonstrate compliance with the underlying permit, license, approval limit or standard. Noncompliance or incomplete documentation of our compliance status may result in the imposition of fines, penalties and injunctive relief. A decision by a government agency to deny or delay the issuance of a new or existing material permit or other approval, or to revoke or substantially modify an existing permit or other approval, could adversely affect our ability to initiate or continue operations at the affected location or facility and on our financial condition, results of operations and cash flows.

Additionally, in order to obtain permits and renewals of permits and other approvals in the future, we may be required to prepare and present data to governmental authorities pertaining to the potential adverse impact that any proposed pipeline or processing-related activities may have on the environment, individually or in the aggregate, including on public and Indian lands. Certain approval procedures may require preparation of archaeological surveys, endangered species studies and other studies to assess the environmental impact of new sites or the expansion of existing sites. Compliance with these regulatory requirements is expensive and significantly lengthens the time required to prepare applications and to receive authorizations.

Costs of compliance with existing environmental laws and regulations are significant, and the cost of compliance with future environmental laws and regulations may adversely affect our results of operations and our ability to make cash distributions to unitholders.

We are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, wildlife conservation, natural resources and health and safety that could, among other things, delay or increase our costs of construction, restrict or limit the output of certain facilities and/or require additional pollution control equipment and otherwise increase costs. There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations and those costs may be even more significant in the future.

Table of Contents

There is inherent risk of the incurrence of environmental costs and liabilities in our operations due to our handling of natural gas, NGLs and crude oil, air emissions related to our operations and historical industry operations and waste disposal practices. These activities are subject to stringent and complex federal, state and local laws and regulations governing environmental protection, including the discharge of materials into the environment and the protection of plants, wildlife, and natural and cultural resources. These laws and regulations can restrict or impact our business activities in many ways, such as restricting the way we can handle or dispose of wastes or requiring remedial action to mitigate pollution conditions that may be caused by our operations or that are attributable to former operators. Joint and several strict liability may be incurred, without regard to fault, under certain of these environmental laws and regulations in connection with discharges or releases of wastes on, under or from our properties and facilities, many of which have been used for midstream activities for a number of years, oftentimes by third parties not under our control. Private parties, including the owners of the properties through which our gathering systems pass and facilities where our wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance, as well as to seek damages for non-compliance, with environmental laws and regulations or for personal injury or property damage. For example, an accidental release from one of our pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. We may be unable to recover these costs from insurance. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase compliance costs and the cost of any remediation that may become necessary. Further, stricter requirements could negatively impact our customers' production and operations, resulting in less demand for our services.

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production by our customers, which could adversely affect our results of operations and our ability to make cash distributions to unitholders.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. Many of our customers commonly use hydraulic fracturing techniques in their drilling and completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas commissions. In addition, certain federal agencies have proposed additional laws and regulations to more closely regulate the hydraulic fracturing process. For example, in January 2015, the EPA indicated its intention to propose more stringent rules regulating methane and VOC emissions from hydraulic fracturing and other well completion activity. Congress from time to time has considered the adoption of legislation to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act (SDWA) and to require disclosure of the chemicals used in the hydraulic fracturing process. Some states have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular, in some cases banning hydraulic fracturing. For example, in Texas, the City of Denton recently enacted a local ordinance that would restrict hydraulic fracturing activities. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where our oil and natural gas exploration and production customers operate, they could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells, some or all of which activities could adversely affect demand for our services to those customers.

In addition, certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The U.S. Environmental Protection Agency, or the EPA, has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. A draft final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources is expected to be available for public comment and peer review by March 2015. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. Other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms.

Our operations may incur substantial liabilities to comply with climate change legislation and regulatory initiatives.

Because our operations emit various types of greenhouse gases, legislation and regulations governing greenhouse gas emissions could increase our costs related to operating and maintaining our facilities, and could delay future permitting. At the federal level, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, require the monitoring and reporting of GHG emissions from specified onshore and offshore oil and natural gas production sources in the United States on an annual basis, which include certain of our operations. Additional EPA rules could affect our ability to obtain air permits for new or modified facilities. In addition, the U.S. Congress has in the past and may in the future consider

Table of Contents

legislation to reduce emissions of greenhouse gases, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. Any such future laws and regulations imposing reporting obligations on, or limiting emissions of, GHGs could require us to incur costs to reduce emissions of GHGs. Substantial limitations on GHG emissions could also adversely affect demand for oil and natural gas. Depending on the particular program, we could in the future be required to purchase and surrender emission allowances or otherwise undertake measures to reduce greenhouse gas emissions. Any additional costs or operating restrictions associated with new legislation or regulations regarding greenhouse gas emissions could have a material adverse effect on our operating results and cash flows, in addition to the demand for our services.

Increased regulatory-imposed costs may increase the cost of consuming, and thereby reduce demand for, the products that we gather, treat and transport. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this view could negatively affect our ability to access capital markets or cause us to receive less favorable terms and conditions. Consequently, legislation and regulatory initiatives aimed at reducing greenhouse gases could have a material adverse effect on our results of operations and our ability to make cash distributions to unitholders.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have a material adverse effect on our operations.

Our operations are subject to extensive regulation by federal regulatory authorities. Changes or additional regulatory measures adopted by such authorities could have a material adverse effect on our results of operations and our ability to make cash distributions to unitholders.

The rates charged by several of our pipeline systems, including for interstate gas transportation service provided by our intrastate pipelines, are regulated by FERC. FERC and state regulatory agencies also regulate other terms and conditions of the services we may offer. If one of these regulatory agencies, on its own initiative or due to challenges by third parties, were to lower our tariff rates or deny any rate increase or other material changes to the types, or terms and conditions, of service we might propose or offer, the profitability of our pipeline businesses could suffer. If we were permitted to raise our tariff rates for a particular pipeline, there might be significant delay between the time the tariff rate increase is approved and the time that the rate increase actually goes into effect, which could also limit our profitability. Furthermore, competition from other pipeline systems may prevent us from raising our tariff rates even if regulatory agencies permit us to do so. The regulatory agencies that regulate our systems periodically implement new rules, regulations and terms and conditions of services subject to their jurisdiction. New initiatives or orders may adversely affect the rates charged for our services or otherwise adversely affect our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders.

Our natural gas interstate pipelines are regulated by FERC under the Natural Gas Act of 1938, or NGA, the Natural Gas Policy Act of 1978, or the NGPA, and the Energy Policy Act of 2005, or EPAct of 2005. Generally, FERC's authority over interstate natural gas transportation extends to:

- rates, operating terms, conditions of service and service contracts;
- certification and construction of new facilities;
- extension or abandonment of services and facilities or expansion of existing facilities;
- maintenance of accounts and records;
- acquisition and disposition of facilities;

- initiation and discontinuation of services;
- depreciation and amortization policies;
- conduct and relationship with certain affiliates;
- market manipulation in connection with interstate sales, purchases or natural gas transportation; and
- various other matters.

FERC’s jurisdiction extends to the certification and construction of interstate transportation and storage facilities, including, but not limited to expansions, lateral and other facilities and abandonment of facilities and services. Prior to commencing construction of significant new interstate transportation and storage facilities, an interstate pipeline must obtain a certificate authorizing the construction, or an order amending its existing certificate, from FERC. Certain minor expansions are authorized by blanket certificates that FERC has issued by rule. Typically, a significant expansion project requires review by a number of governmental agencies, including state and local agencies, whose cooperation is important in completing the regulatory process on schedule. Any failure by an agency to issue sufficient authorizations or permits in a timely manner for one or more of these projects may mean that we will not be able to pursue these projects or that they will be constructed in a manner or with capital requirements that we did not anticipate. Our inability to obtain sufficient permits and authorizations in a timely manner could materially and negatively impact the additional revenues expected from these projects.

FERC conducts audits to verify compliance with FERC's regulations and the terms of its orders, including whether the websites of interstate pipelines accurately provide information on the operations and availability of services. FERC's regulations require uniform terms and conditions for service, as set forth in agreements for transportation and storage services executed between interstate pipelines and their customers. These service agreements are required to conform, in all material respects, with the standard form of service agreements set forth in the pipeline's FERC-approved tariff. Non-conforming agreements must be filed with, and accepted by, the FERC. In the event that FERC finds that an agreement, in whole or part, is materially non-conforming, it could reject the agreement or require us to seek modification, or alternatively require us to modify our tariff so that the non-conforming provisions are generally available to all customers.

The rates, terms and conditions for transporting natural gas in interstate commerce on certain of our intrastate pipelines and for services offered at certain of our storage facilities are subject to the jurisdiction of FERC under Section 311 of the NGPA. Rates to provide such interstate transportation service must be "fair and equitable" under the NGPA and are subject to review, refund with interest if found not to be fair and equitable, and approval by FERC at least once every five years.

Our crude oil gathering pipelines are subject to common carrier regulation by FERC under the Interstate Commerce Act, or ICA. The ICA requires that we maintain tariffs on file with FERC setting forth the rates we charge for providing transportation services, as well as the rules and regulations governing such services. The ICA requires, among other things, that our rates must be "just and reasonable" and that we provide service in a manner that is nondiscriminatory. Shippers on our crude oil gathering pipelines may protest our tariff filings, file complaints against our existing rates, or FERC can investigate our rates on its own initiative. In the event that FERC finds that our existing or proposed rates are unjust and unreasonable, it could deny requested rate increases or could order us to reduce our rates and could require the payment of reparations to complaining shippers for up to two years prior to the complaint.

Our operations may also be subject to regulation by state and local regulatory authorities. Changes or additional regulatory measures adopted by such authorities could adversely affect our results of operations and our ability to make cash distributions to unitholders.

Our pipeline operations that are not regulated by FERC may be subject to state and local regulation applicable to intrastate natural and transportation services. The relevant states in which we operate include North Dakota, Oklahoma, Arkansas, Louisiana, Texas, Missouri, Kansas, Mississippi, Tennessee and Illinois. State and local regulations generally focus on safety, environmental and, in some circumstances, prohibition of undue discrimination among shippers. Additional rules and legislation pertaining to these matters are considered and, in some instances, adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but we could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes. Other state and local regulations also may affect our business. Any such state or local regulation could have an adverse effect on our business and the results of our operations.

Our gathering lines may be subject to ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, oil or natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes restrict our right as an owner of gathering facilities to decide with whom we contract to purchase or transport oil or natural gas. Federal law leaves economic regulation of natural gas gathering to the states. The states in which we operate have adopted complaint-based regulation of oil and natural gas gathering activities, which allows oil and natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to access to oil and natural gas gathering pipelines and rate discrimination.

Other state regulations may not directly regulate our business, but may nonetheless affect the availability of natural gas for processing, including state regulation of production rates and maximum daily production allowable from gas wells. While our gathering lines are currently subject to limited state regulation, there is a risk that state laws will be changed, which may give producers a stronger basis to challenge the regulatory status of a line, or the rates, terms and conditions of a gathering line providing transportation service.

Table of Contents

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Our natural gas gathering and intrastate transportation operations are generally exempt from the jurisdiction of FERC under the NGA, but FERC regulation may indirectly impact these businesses and the markets for products derived from these businesses. FERC's policies and practices across the range of its oil and natural gas regulatory activities, including, for example, its policies on interstate open access transportation, ratemaking, capacity release, and market center promotion may indirectly affect intrastate markets. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate oil and natural gas pipelines. However, we cannot assure you that FERC will continue to pursue this approach as it considers matters such as pipeline rates and rules and policies that may indirectly affect the intrastate natural gas transportation business. Although FERC has not made a formal determination with respect to all of our facilities we consider to be gathering facilities, management believes that our natural gas gathering pipelines meet the traditional tests that FERC has used to determine that a pipeline is a gathering pipeline and are therefore not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities is subject to change based on future determinations by FERC, the courts or Congress. If FERC were to consider the status of an individual facility and determine that the facility and/or services provided by it are not exempt from FERC regulation under the NGA and that the facility provides interstate service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by FERC under the NGA or the NGPA. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of substantial civil penalties, as well as a requirement to disgorge revenues collected for such services in excess of the maximum rates established by FERC.

Natural gas gathering may receive greater regulatory scrutiny at the state level; therefore, our natural gas gathering operations could be adversely affected should they become subject to the application of state regulation of rates and services. Our gathering operations could also be subject to safety and operational regulations relating to the design, construction, testing, operation, replacement and maintenance of gathering facilities. We cannot predict what effect, if any, such changes might have on our operations, but we could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

We may incur significant costs and liabilities resulting from pipeline integrity and other similar programs and related repairs.

The U.S. Department of Transportation, or DOT, has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines located in "high consequence areas," which are those areas where a leak or rupture could do the most harm. The regulations require operators, including us, to, among other things:

- develop a baseline plan to prioritize the assessment of a covered pipeline segment;
- identify and characterize applicable threats that could impact a high consequence area;
- improve data collection, integration, and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating action.

Although many of our pipelines fall within a class that is currently not subject to these requirements, we may incur significant cost and liabilities associated with repair, remediation, preventive or mitigation measures associated with our non-exempt pipelines. This work is part of our normal integrity management program and we do not expect to incur any extraordinary costs during 2015 to complete the testing required by existing DOT regulations and their state counterparts. We have not estimated the costs for any repair, remediation, preventive or mitigation actions that may be determined to be necessary as a result of the testing program, which could be substantial, or any lost cash flows resulting from shutting down our pipelines during the pendency of such repairs. Should we fail to comply with DOT or comparable state regulations, we could be subject to penalties and fines. Also, the scope of the integrity management program and other related pipeline safety programs could be expanded in the future. We have not estimated the cost of complying with such future requirements.

The adoption of financial reform legislation by the United States Congress could adversely affect our ability to use derivative instruments to hedge risks associated with our business.

At times, we may hedge all or a portion of our commodity risk and our interest rate risk. The United States Congress adopted comprehensive financial reform legislation that changed federal oversight and regulation of the derivatives markets and entities, including businesses like ours, that participate in those markets. The new legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, was signed into law by the President on July 21, 2010, and requires the Commodity Futures Trading Commission, or the CFTC, and the SEC to promulgate rules and regulations implementing the legislation. In its rulemaking under the Dodd-Frank Act, the CFTC adopted regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents, but these rules were successfully challenged in federal district court by the Securities Industry Financial Markets Association and the International Swaps and Derivatives Association and largely vacated by the court. The CFTC appealed this ruling, but subsequently withdrew its appeal. In December 2013, the CFTC published a Notice of Proposed Rulemaking designed to implement new position limits regulation. The ultimate form and timing of the implementation of the regulatory regime affecting commodity derivatives remains uncertain. However, reporting obligations for transactions involving non-financial swap counterparties such as us began on July 1, 2013 with regard to interest rate swaps and August 19, 2013 with regard to other commodity swaps such as natural gas swap products.

Under final rules adopted by the CFTC, management believes our hedging transactions will qualify for the non-financial, commercial end-user exception, which exempts derivatives intended to hedge or mitigate commercial risk from the mandatory swap clearing requirement, where the counterparty such as us has a required identification number, is not a financial entity as defined by the regulations, and meets a minimum asset test. The Dodd-Frank Act may also require us to comply with margin requirements in connection with our hedging activities, although the application of those provisions to us is uncertain at this time. The Dodd-Frank Act may also require the counterparties to our derivative instruments to spin off some of their hedging activities to a separate entity, which may not be as creditworthy as the current counterparty.

The Dodd-Frank Act and related regulations could significantly increase the cost of derivatives contracts for our industry (including requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivatives contracts, and increase our exposure to less creditworthy counterparties, particularly if we are unable to utilize the commercial end user exception with respect to certain of our hedging transactions. If we reduce our use of hedging as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and fund unitholder distributions. Finally, the legislation was intended, in part, to reduce the volatility of crude oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to crude oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could adversely affect our results of operations and our ability to make cash distributions to unitholders.

Risks Related to an Investment in Us

Our general partner and its affiliates, including CenterPoint Energy and OGE Energy, have conflicts of interest with us and limited duties to us and our unitholders, and they may favor their own interests to the detriment of us and our other common unitholders.

Affiliates of CenterPoint Energy and OGE Energy own and control our general partner and appoint all of the officers and directors of our general partner. Some of the directors of our general partner are also directors of CenterPoint Energy or OGE Energy. Although our general partner has a duty to manage us in a manner that is beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner that is beneficial to CenterPoint Energy and OGE Energy. Conflicts of interest will arise between

CenterPoint Energy, OGE Energy and our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of CenterPoint Energy and OGE Energy over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

- Neither our partnership agreement nor any other agreement requires CenterPoint Energy or OGE Energy to pursue a business strategy that favors us. The directors and officers of CenterPoint Energy and OGE Energy have a fiduciary duty to make decisions in the best interests of the stockholders of their respective companies, which may be contrary to our interests. CenterPoint Energy and OGE Energy may choose to shift the focus of their investment and growth to areas not served by our assets.
- Our general partner is allowed to take into account the interests of parties other than us, such as CenterPoint Energy and OGE Energy, in resolving conflicts of interest.
- Some of the directors of our general partner are also directors of CenterPoint Energy or OGE Energy and will owe fiduciary duties to their respective companies. These individuals may also devote significant time to the business of CenterPoint Energy and OGE Energy.

Table of Contents

- Our partnership agreement replaces the fiduciary duties that would otherwise be owed to us by our general partner with contractual standards governing its duties, limits our general partner’s liabilities and restricts the remedies available to our unitholders for actions that, without such limitations, might constitute breaches of fiduciary duty.
- Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.
- Disputes may arise under our commercial agreements with CenterPoint Energy and OGE Energy.
- Our general partner determines the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership units and the creation, reduction or increase of cash reserves, each of which can affect the amount of distributable cash flow.
- Our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion or investment capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and the ability of the subordinated units to convert to common units.
- Our general partner determines which costs incurred by it and its affiliates are reimbursable by us.
- Our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period.
- Our partnership agreement permits us to classify up to $300 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions on our subordinated or general partner units or to our general partner in respect of the incentive distribution rights.
- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf.
- Our general partner intends to limit its liability regarding our contractual and other obligations.
- Our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 90% of the common units. If our general partner and its affiliates reduce their ownership percentage to below 70% of the outstanding units, the ownership threshold to exercise the call right will be permanently reduced to 80%.
- Our general partner controls the enforcement of the obligations that it and its affiliates owe to us.
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.
- Our general partner may transfer its incentive distribution rights without unitholder approval.
- Our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our general partner’s incentive distribution rights without the approval of the conflicts committee of the Board of Directors or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

If a unitholder is not an Eligible Holder, the unitholder's common units may be subject to redemption.

Our partnership agreement includes certain requirements regarding those investors who may own our common and subordinated units. Eligible Holders are limited partners whose (i) federal income tax status is not reasonably likely to have a material adverse effect on the rates that can be charged by us on assets that are subject to regulation by FERC or an analogous regulatory body and (ii) nationality, citizenship or other related status would not create a substantial risk of cancellation or forfeiture of any property in which we have an interest, in each case as determined by our general partner with the advice of counsel. If the unitholder is not an Eligible Holder, in certain circumstances as set forth in our partnership agreement, the unitholder's units may be redeemed by us at the then-current market price. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner.
Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.

Our partnership agreement requires that we distribute all of our available cash to our unitholders and will rely primarily upon external financing sources, including commercial borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow.

Table of Contents

In addition, because we intend to distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement or in our credit facilities that limit our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which in turn may impact the available cash that we have to distribute to our unitholders.

The reimbursements due to our general partner and its affiliates for services provided to us or on our behalf will reduce our distributable cash flow. The amount and timing of such reimbursements will be determined by our general partner.

Prior to making any distribution on our common units, we will reimburse our general partner and its affiliates, including CenterPoint Energy and OGE Energy, for costs and expenses they incur and payments they make on our behalf. Pursuant to services agreements we have entered into with each of CenterPoint Energy and OGE Energy, we will reimburse CenterPoint Energy and OGE Energy for the payment of operating expenses related to our operations and for the provision of various general and administrative services performed for our benefit. Payments for these services may be substantial and will reduce the amount of distributable cash flow. Additionally, we will reimburse CenterPoint Energy and OGE Energy for direct or allocated costs and expenses incurred on our behalf, including administrative costs, such as compensation expense for those persons who provide services necessary to run our business, and insurance expenses. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. The reimbursement of expenses and payment of fees, if any, to our general partner and its affiliates will reduce the amount of available cash to pay cash distributions to our common unitholders.

Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships.

We cannot assure you that our credit ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Any future downgrade could increase the cost of short-term borrowings or prevent us from accessing the commercial paper markets. Any downgrade could also lead to higher borrowing costs and, if below investment grade, could require us or our subsidiaries to post cash collateral under our shipping or hedging arrangements or in order to purchase natural gas or letters of credit. If a credit rating downgrade and the resultant cash collateral requirement were to occur at a time when we were experiencing significant working capital requirements or otherwise lacked liquidity, our results of operations and our ability to make cash distributions to unitholders could be adversely affected.
The credit and business risk profiles of our general partner, CenterPoint Energy and OGE Energy could adversely affect our credit ratings and profile.

The credit and business risk profiles of our general partner, CenterPoint Energy and OGE Energy may be factors in credit evaluations of a master limited partnership because our general partner can exercise control over our business activities, including our cash distribution and acquisition strategy and business risk profile. Other factors that may be considered are the financial conditions of our general partner, CenterPoint Energy and OGE Energy, including the degree of their financial leverage and their dependence on cash flows from us to service their indebtedness.

CenterPoint Energy and OGE Energy, which indirectly own our general partner, have indebtedness outstanding and are partially dependent on the cash distributions from their general partner and limited partner interests in us to service such indebtedness and pay dividends on their common stock. Any distributions by us to such entities will be made only after satisfying our then-current obligations to our creditors. Our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of the entities that control our general partner were viewed as substantially lower or more risky than ours.

Our partnership agreement replaces our general partner's fiduciary duties to holders of our common units with contractual standards governing its duties.

Our partnership agreement contains provisions that eliminate the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law and replaces those duties with several different contractual standards. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, free of any duties to us and our unitholders other than the implied contractual covenant of good faith and fair dealing, which means that a court will enforce the reasonable expectations of the partners where the language in the partnership agreement does not provide for a clear course of action. This provision entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

Table of Contents

- how to allocate corporate opportunities among us and its other affiliates;
- whether to exercise its limited call right;
- whether to seek approval of the resolution of a conflict of interest by the conflicts committee of the Board of Directors;
- whether to elect to reset target distribution levels;
- whether to transfer the incentive distribution rights to a third party; and
- whether or not to consent to any merger or consolidation of the Partnership or amendment to the partnership agreement.

By purchasing a common unit, a common unitholder agrees to become bound by the provisions in the partnership agreement, including the provisions discussed above.

Our partnership agreement restricts the remedies available to holders of our common units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement provides that:

- whenever our general partner, the Board of Directors or any committee thereof (including the conflicts committee) makes a determination or takes, or declines to take, any other action in their respective capacities, our general partner, the Board of Directors and any committee thereof (including the conflicts committee), as applicable, is required to make such determination, or take or decline to take such other action, in good faith, meaning that it subjectively believed that the decision was in the best interests of the Partnership, and, except as specifically provided by our partnership agreement, will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;
- our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as such decisions are made in good faith;
- our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and
- our general partner will not be in breach of its obligations under the partnership agreement (including any duties to us or our unitholders) if a transaction with an affiliate or the resolution of a conflict of interest is:
- approved by the conflicts committee of the Board of Directors, although our general partner is not obligated to seek such approval;
- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;
- determined by the Board of Directors to be on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- determined by the Board of Directors to be fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner or the conflicts committee must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee and the Board of Directors determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in the third and fourth subbullets above, then it will be presumed that, in making its decision, the Board of Directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the Partnership challenging such determination, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Table of Contents

Our general partner may elect to cause us to issue common units to it in connection with a resetting of the minimum quarterly distribution and the target distribution levels related to our general partner’s incentive distribution rights without the approval of the conflicts committee of our general partner or our unitholders. This may result in lower distributions to our common unitholders in certain situations.

Our general partner has the right, at any time when there are no subordinated units outstanding, if it has received incentive distributions at the highest level to which it is entitled (50.0%) for each of the prior four consecutive fiscal quarters and the amount of each such distribution did not exceed the adjusted operating surplus for such quarter, respectively, to reset the initial minimum quarterly distribution and cash target distribution levels at higher levels based on the average cash distribution amount per common unit for the two fiscal quarters prior to the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the reset minimum quarterly distribution) and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution amount.

We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that our general partner could exercise this reset election at a time when we are experiencing declines in our aggregate cash distributions or at a time when our general partner expects that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, our general partner may be experiencing, or may be expected to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued our common units, which are entitled to specified priorities with respect to our distributions and which therefore may be more advantageous for the general partner to own in lieu of the right to receive incentive distribution payments based on target distribution levels that are less certain to be achieved in the then-current business environment. This risk could be elevated if our incentive distribution rights have been transferred to a third party. Our general partner has the right to transfer the incentive distribution rights at any time, in whole or in part, and any transferee holding a majority of the incentive distribution rights shall have the same rights as our general partner with respect to resetting target distributions. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new common units to our general partner in connection with resetting the target distribution levels related to our general partner incentive distribution rights.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management’s decisions regarding our business. Unitholders will have no right to elect our general partner or its Board of Directors on an annual or other continuing basis. Because CenterPoint Energy and OGE Energy collectively indirectly own 100% of our general partner, the Board of Directors has been, and, as long as CenterPoint Energy and OGE Energy own 100% of our general partner, will continue to be, chosen by CenterPoint Energy and OGE Energy. Furthermore, if the unitholders were dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. Please see “—Even if holders of our common units are dissatisfied, they will not be able to remove our general partner without its consent.” As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders’ ability to influence the manner or direction of management.

Even if holders of our common units are dissatisfied, they will not be able to remove our general partner without its consent.

The unitholders are unable to remove our general partner without its consent because affiliates of our general partner own sufficient units to be able to prevent its removal. The vote of the holders of at least 75% of all outstanding units voting together as a single class is required to remove our general partner. As of February 2, 2015, affiliates of our general partner owned 81.7% of our aggregate outstanding common and subordinated units. Also, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on our common units will be extinguished. A removal of our general partner under these circumstances would adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. “Cause” is narrowly defined under our partnership agreement to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable for actual fraud or willful misconduct in its capacity as our general partner. “Cause” does not include most cases of charges of poor management of the business, so the removal of our general partner because of the unitholders’ dissatisfaction with our general partner’s

Table of Contents

performance in managing us will most likely result in the termination of the subordination period and conversion of all subordinated units to common units.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Unitholders' voting rights are further restricted by a provision of our partnership agreement providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the Board of Directors, cannot vote on any matter.

Our general partner's interest in us and control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Although the limited liability company agreement of our general partner restricts the ability of CenterPoint Energy and OGE Energy to transfer their ownership of their respective limited liability company interest in our general partner until May 1, 2016, our partnership agreement does not restrict the ability of the owners of our general partner from transferring all or a portion of their respective limited liability company interest in our general partner to a third party. The new owners of our general partner would then be in a position to replace the Board of Directors and executive officers of our general partner with its own choices and thereby influence the decisions taken by the Board of Directors and executive officers.

The incentive distribution rights of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its incentive distribution rights to a third party at any time without the consent of our unitholders. If our general partner transfers its incentive distribution rights to a third party but retains its general partner interest, our general partner may not have the same incentive to grow the Partnership and increase quarterly distributions to unitholders over time as it would if it had retained ownership of its incentive distribution rights. For example, a transfer of incentive distribution rights by our general partner could reduce the likelihood of CenterPoint Energy or OGE Energy selling or contributing additional assets to us, as they would have less of an economic incentive to grow our business, which in turn would impact our ability to grow our asset base.

We may issue additional units without your approval, which would dilute your existing ownership interests.

Our partnership agreement does not limit the number of additional limited partner interests, including limited partner interests that rank senior to the common units, that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our existing unitholders' proportionate ownership interest in us will decrease;
- the amount of distributable cash flow on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- because the amount payable to holders of incentive distribution rights is based on a percentage of the total distributable cash flow, the distributions to holders of incentive distribution rights will increase even if the per unit distribution on common units remains the same;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Affiliates of our general partner may sell common units in the public or private markets, which could have an adverse impact on the trading price of the common units.

As of February 2, 2015, subsidiaries of CenterPoint Energy and OGE Energy hold an aggregate of 136,958,657 common units and 207,855,430 subordinated units. All of the subordinated units will convert into common units at the end of the subordination period and some may convert earlier under certain circumstances. In addition, we have agreed to provide CenterPoint Energy, OGE Energy and ArcLight with certain registration rights. The sale of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

Table of Contents

Our general partner has a limited call right that may require our unitholders to sell their units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 90% of the common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price, as calculated pursuant to the terms of the partnership agreement. If our general partner and its affiliates reduce their ownership percentage to below 70% of the outstanding units, the ownership threshold to exercise the call right will be permanently reduced to 80%. As a result, our unitholders may be required to sell their common units at an undesirable time or price and may not receive any positive return on their investment. Our unitholders may also incur a tax liability upon any such sale of their units. As of February 2, 2015, affiliates of our general partner owned approximately 63.9% of our outstanding common units. At the end of the subordination period, assuming no additional issuances of common units (other than upon the conversion of the subordinated units), affiliates of our general partner will own approximately 81.7% of our aggregate outstanding common units. Affiliates of our general partner may acquire additional common units from us in connection with future transactions or through open-market or negotiated purchases.

Our unitholders' liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. The Partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we may do business. Our unitholders could be held liable for any and all of our obligations as if they were general partners if a court or government agency were to determine that:

- we were conducting business in a state but had not complied with that particular state’s partnership statute; or
- a unitholder's right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitutes “control” of our business.

Our partnership agreement designates the Court of Chancery of the State of Delaware as the exclusive forum for certain types of actions and proceedings that may be initiated by our unitholders, which limits our unitholders’ ability to choose the judicial forum for disputes with us or our general partner’s directors, officers or other employees.

Our partnership agreement provides, that, with certain limited exceptions, the Court of Chancery of the State of Delaware is the exclusive forum for any claims, suits, actions or proceedings (1) arising out of or relating in any way to our partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of our partnership agreement or the duties, obligations or liabilities among our partners, or obligations or liabilities of our partners to us, or the rights or powers of, or restrictions on, our partners or us), (2) brought in a derivative manner on our behalf, (3) asserting a claim of breach of a duty (including a fiduciary duty) owed by any of our, or our general partner’s, directors, officers, or other employees, or owed by our general partner, to us or our partners, (4) asserting a claim against us arising pursuant to any provision of the Delaware Revised Uniform Limited Partnership Act or (5) asserting a claim against us governed by the internal affairs doctrine. Any person or entity purchasing or otherwise acquiring any interest in our common units is deemed to have received notice of and consented to the foregoing provisions. Although management believes this choice of forum provision benefits us by providing increased consistency in the application of Delaware law in the types of lawsuits to which it applies, the provision may have the effect of discouraging lawsuits against us and our general partner’s directors and officers. The enforceability of similar choice of forum provisions in other companies’ certificates of incorporation or similar governing documents has been challenged in legal proceedings and it is possible that in connection with any action a court could find the choice of forum provisions contained in our partnership agreement to be inapplicable or unenforceable in such action. If a court were to find this choice of forum provision inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition and results of operations and our ability to make cash distributions to our unitholders.

The NYSE does not require a publicly traded limited partnership like us to comply with certain of its corporate governance requirements.

Our common units are listed on the NYSE. Because we are a publicly traded limited partnership, the NYSE does not require us to have, and we do not intend to have, a majority of independent directors on our Board of Directors or to establish a nominating and corporate governance committee. Accordingly, unitholders will not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements.

Table of Contents

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, which we refer to herein as the Delaware Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Transferees of common units are liable for both the obligations of the transferor to make contributions to the Partnership that are known to the transferee at the time of transfer and for unknown obligations if the liabilities could have been determined from the partnership agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the Partnership are counted for purposes of determining whether a distribution is permitted.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that the counterparties to such arrangements have recourse only against our assets and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are non-recourse to our general partner. Our partnership agreement permits our general partner to limit its liability, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

An increase in interest rates could adversely impact the price of our common units, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, the market price of our common units is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield-oriented securities for investment decision purposes. Therefore, changes in interest rates may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on the price of our common units, our ability to issue additional equity to make acquisitions or for other purposes and our ability to make cash distributions at our intended levels.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the IRS were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, then our distributable cash flow to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested a ruling from the Internal Revenue Service, or IRS, on this or any other tax matter affecting us.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. A change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35.0%, and would likely pay state and local income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to such unitholders. Because a tax would be imposed upon us as a corporation, our distributable cash flow to our unitholders would be substantially reduced. Therefore, if we were treated as a corporation for federal income tax purposes there would be material reductions in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

Table of Contents

If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our distributable cash flow to our unitholders.

Changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of such additional tax on us by a state will reduce the distributable cash flow. Our partnership agreement provides that, if a law is enacted or an existing law is modified or interpreted in a manner that subjects us to entity-level taxation, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations of applicable law, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. From time to time, members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Any modification to the federal income tax laws and interpretations thereof could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes. We are unable to predict whether any such changes will ultimately be enacted, but it is possible that a change in law could affect us and may, if enacted, be applied retroactively. Any such changes could negatively impact the value of an investment in our common units.

Our unitholders’ share of our income will be taxable to them for U.S. federal income tax purposes even if they do not receive any cash distributions from us.

Because a unitholder will be treated as a partner to whom we will allocate taxable income which could be different in amount than the cash we distribute, a unitholder’s allocable share of our taxable income will be taxable to it, which may require the payment of federal income taxes and, in some cases, state and local income taxes on such unitholder's share of our taxable income even if it receives no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest would likely reduce our distributable cash flow to unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel expressed in a prospectus or from the positions we take, and the IRS’s positions may ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel’s conclusions or the positions we take and such positions may not ultimately be sustained. A court may not agree with some or all of our counsel’s conclusions or the positions we take. Any contest with the IRS, and the outcome of any IRS contest, may have a materially adverse effect on the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS would be borne indirectly by our unitholders and our general partner because the costs would likely reduce our distributable cash flow to our unitholders.

Tax gain or loss on the disposition of our common units could be more or less than expected.

If any of our unitholders sells their common units, such unitholders must recognize a gain or loss for federal income tax purposes equal to the difference between the amount realized and such unitholder's tax basis in those common units. Because distributions in excess of such unitholder's allocable share of our net taxable income decrease such unitholder's tax basis in such unitholder's common units, the amount, if any, of such prior excess distributions with respect to the common units such unitholders sells will, in effect, become taxable income if such unitholders sells such common units at a price greater than its tax basis in those common units, even if the price such unitholder receives is less than its original cost. Furthermore, a substantial portion of the amount realized on any sale or other disposition of such unitholder's common units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if a unitholder sells its common units, it may incur a tax liability in excess of the amount of cash it receives from the sale.

Table of Contents

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in our common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult a tax advisor before investing in our common units.

We treat each holder of our common units as having the same tax benefits without regard to the actual common units held. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. A successful IRS challenge also could affect the timing of these tax benefits or the amount of gain from a unitholder's sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to such unitholder's tax returns.

We prorate our items of income, gain, loss and deduction for U.S. federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We will prorate our items of income, gain, loss and deduction for U.S. federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and although the U.S. Treasury Department issued proposed Treasury Regulations allowing a similar monthly simplifying convention, such regulations are not final and do not specifically authorize the use of the proration method we will adopt. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose common units are loaned to a “short seller” to cover a short sale of common units may be considered as having disposed of those common units. If so, such unitholder would no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose common units are loaned to a “short seller” to cover a short sale of common units may be considered as having disposed of the loaned common units, such unitholder may no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan to the short seller and may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Therefore, our unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from loaning their common units.

We have adopted certain valuation methodologies and monthly conventions for U.S. federal income tax purposes that may result in a shift of income, gain, loss and deduction between our general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of taxable income, gain, loss and deduction between our general partner and certain of our unitholders.

Table of Contents

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of taxable gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profits interests during any 12-month period will result in the termination of the Partnership for federal income tax purposes.

We will be considered to have technically terminated the Partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year if the termination occurs on a day other than December 31 and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than 12 months of our taxable income or loss being includable in such unitholder's taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests publicly traded partnership technical termination relief and such relief is granted by the IRS, among other things, the Partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

As a result of investing in our common units, our unitholders will likely be subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire properties.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own property and conduct business in a number of states, most of which currently impose a personal income tax on individuals, and most of which also impose an income or similar tax on corporations and certain other entities. As we make acquisitions or expand our business, we may own property or conduct business in additional states that impose an income tax or similar tax. In certain states, tax losses may not produce a tax benefit in the year incurred and also may not be available to offset income in subsequent tax years. Some states may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be greater or less than a particular unitholders' income tax liability to the state, generally does not relieve a nonresident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us.

Compliance with and changes in tax laws could adversely affect our performance.

We are subject to extensive tax laws and regulations, including federal and state income taxes and transactional taxes such as excise, sales/use, payroll, franchise and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted that could result in increased tax expenditures in the future. Many of these tax liabilities are subject to audits by the respective taxing authority. These audits may result in additional taxes as well as interest and penalties.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties

Our real property falls into two categories: (i) parcels that we own in fee and (ii) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. Certain of our processing plants and related facilities are located on land we own in fee, and management

Table of Contents

believes that we have satisfactory title to these lands. The remainder of the land on which our plants and related facilities are located is held by us pursuant to ground leases between us, or our subsidiaries, as lessee, and the fee owner of the lands, as lessors, and management believes that we have satisfactory leasehold estates to such lands. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our title to any material lease, easement, right-of-way, permit or lease, and management believes that we have satisfactory title to all of our material leases, easements, rights-of-way, permits and licenses.

Record title to some of our assets may reflect names of prior owners until we have made the appropriate filings in the jurisdictions in which such assets are located. Title to some of our assets may be subject to encumbrances. Management believes that none of such encumbrances should materially detract from the value of our properties or our interest in those properties or should materially interfere with our use of them in the operation of our business. Substantially all of our pipelines are constructed on rights-of-way granted by the apparent owners of record of the properties. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the rights-of-way grants.

Our principal executive offices are located at One Leadership Square, 211 North Robinson Avenue, Suite 950, Oklahoma City, Oklahoma 73102; our telephone number is 405-525-7788.

We currently occupy 162,053 square feet of office space at our principal executive offices under a lease that expires June 30, 2019. Although we may require additional office space as our business expands, management believes that our current facilities are adequate to meet our needs for the immediate future. In addition to our executive offices, we own numerous facilities throughout our service territory that support our operations. These facilities include, but are not limited to, district offices, fleet and equipment service facilities, compressor station facilities, operation support and other properties.

Please see Item 1. "Business — Our Assets and Operations" for further discussion of our property.

Item 3. Legal Proceedings

In the normal course of business, we are confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If, in management’s opinion, we have incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in our Combined and Consolidated Financial Statements. At the present time, based on currently available information, management believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to our financial statements and would not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Item 4. Mine Safety Disclosures

Not applicable.

Part II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information

Our common units are listed on the NYSE under the symbol “ENBL.” The following table sets forth the high and low sales prices of the common units as well as the amount of cash distributions declared and paid on the common units during each quarter since our Offering.

Table of Contents

	Common Units		
	High	Low	Distribution per common unit
Year ended December 31, 2014			
Fourth Quarter	$24.93	$17.40	$0.30875
Third Quarter	26.75	23.78	0.3025
Second Quarter(1)	26.19	22.20	0.2464

(1) The quarterly distribution for three months ended June 30, 2014 was prorated for the period beginning immediately after the closing of the Partnership's Offering, April 16, 2014 through June 30, 2014.

On January 23, 2015, the Board of Directors declared a quarterly distribution of $0.30875 per unit, which was paid on February 13, 2015, to unitholders of record at the close of business on February 4, 2015. The last reported sale price of our common units on the NYSE on February 2, 2015 was $17.60. As of February 2, 2015, there were 214,455,154 common units outstanding and approximately 14 unitholders of record of our common units. This number does not include unitholders whose units are held in trust by other entities. The actual number of unitholders is greater than the number of holders of record. We have also issued 207,855,430 subordinated units and ownership interests in the general partner, for which there is no established public trading market. All of the subordinated units and general partner interests are held by affiliates of our general partner.

Distributions of Available Cash

General

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our Available Cash (defined below) to unitholders of record on the applicable record date.

Definition of Available Cash

Available cash is defined in our partnership agreement, which is an exhibit to the Annual Report on Form 10-K. Available cash generally means, for any quarter, all cash and cash equivalents on hand at the end of that quarter:

- less, the amount of cash reserves established by our general partner to:
- provide for the proper conduct of our business (including cash reserves for our future capital expenditures, future acquisitions, and anticipated future debt service requirements and refunds of collected rates reasonably likely to be refunded as a result of a settlement or hearing related to FERC rate proceedings or rate proceedings under applicable law subsequent to that quarter);
- comply with applicable law, any of our debt instruments or other agreements; or
- provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters (provided that our general partner may not establish cash reserves for distributions if the effect of the establishment of such reserves will prevent us from distributing the minimum quarterly distribution on all common units and any cumulative arrearages on such common units for the current quarter);
- plus, if our general partner so determines, all or any portion of the cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made subsequent to the end of such quarter.

Minimum Quarterly Distribution

The Minimum Quarterly Distribution, as set forth in the partnership agreement, is $0.2875 per unit per quarter, or $1.15 per unit on an annualized basis to the extent we have sufficient cash from our operations after the establishment of cash reserves and the payment of costs and expenses, including reimbursements of expenses to our general partner. Our current quarterly distribution is $0.30875 per unit, or $1.235 per unit annualized. However, there is no guarantee that we will pay the minimum quarterly distribution on our units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement. Please read Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources” for a discussion of the restrictions included in our credit agreement that may restrict our ability to make distributions.

Table of Contents

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 our 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. Please read Note 5 of the Notes to Consolidated Financial Statements in Item 8. “Financial Statements and Supplementary Data” for additional information.

Percentage Allocations of Available Cash from Operating Surplus

The following table illustrates the percentage allocations of available cash from operating surplus between the unitholders and our general partner (through the incentive distribution rights) based on the specified target distribution levels. The amounts set forth under “Marginal Percentage Interest in Distributions” are the percentage interests of our general partner and the unitholders in any available cash from operating surplus we distribute up to and including the corresponding amount in the column “Total Quarterly Distribution Per Unit Target Amount.” The percentage interests shown for our unitholders for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our general partner assume that our general partner has not transferred its incentive distribution rights and that there are no arrearages on common units.

	Total Quarterly Distribution Per Unit Target Amount	Marginal Percentage Interest in Distributions			
		Unitholders		General Partner	
Minimum Quarterly Distribution	$0.2875	100.0	%	—	%
First Target Distribution	up to $0.330625	100.0	%	—	%
Second Target Distribution	above $0.330625 up to $0.359375	85.0	%	15.0	%
Third Target Distribution	above $0.359375 up to $0.431250	75.0	%	25.0	%
Thereafter	above $0.431250	50.0	%	50.0	%

Subordination Period

General

Our partnership agreement provides that, during the subordination period (which we define below), the common units will have the right to receive distributions of available cash from operating surplus each quarter in an amount equal to $0.2875 per common unit, which amount is defined in our partnership agreement as the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. These units are deemed “subordinated” because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the minimum quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units.

Definition of Subordination Period

Except as described below, the subordination period began on the closing date of the Offering and will extend until the first business day following the distribution of available cash in respect of any quarter beginning with the quarter ending June 30, 2017, that each of the following tests are met:

- distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded $1.15 per unit (the annualized minimum quarterly distribution), for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;
- the adjusted operating surplus generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of $1.15 (the annualized minimum quarterly distribution) on all of the outstanding common units and subordinated units during those periods on a fully diluted basis; and

Table of Contents

- there are no arrearages in payment of the minimum quarterly distribution on the common units.

Early Termination of Subordination Period

Notwithstanding the foregoing, the subordination period will automatically terminate on the first business day following the distribution of available cash in respect of any quarter beginning with the quarter ending June 30, 2015, that each of the following tests are met:

- distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded $1.725 (150% of the annualized minimum quarterly distribution) for the four-consecutive-quarter period immediately preceding that date;
- the adjusted operating surplus generated during the four-consecutive-quarter period immediately preceding that date equaled or exceeded the sum of (i) $1.725 per unit (150% of the annualized minimum quarterly distribution) on all of the outstanding common units and subordinated units during that period on a fully diluted basis and (ii) the corresponding distributions on the incentive distribution rights; and
- there are no arrearages in payment of the minimum quarterly distributions on the common units.

Expiration of the Subordination Period

When the subordination period ends, each outstanding subordinated unit will convert into one common unit and will thereafter participate pro rata with the other common units in distributions of available cash. In addition, if the unitholders remove our general partner other than for cause:

- the subordinated units held by any person will immediately and automatically convert into common units on a one-for-one basis, provided (i) neither such person nor any of its affiliates voted any of its units in favor of the removal and (ii) such person is not an affiliate of the successor general partner;
- if all of the subordinated units convert pursuant to the foregoing, all cumulative common unit arrearages on the common units will be extinguished and the subordination period will end; and
- our general partner will have the right to convert its general partner interest and its incentive distribution rights into common units or to receive cash in exchange for those interests.

Equity Compensation Plans

The information relating to our equity compensation plans required by Item 5 is incorporated by reference to such information as set forth in Item 12. “Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters” contained herein.

Table of Contents

Item 6. Selected Financial Data

The following tables set forth, for the periods and as of the dates indicated, the selected historical financial and operating data of Enable Midstream Partners, LP, which is derived from the historical books and records of the Partnership. On May 1, 2013 (formation), OGE Energy and ArcLight indirectly contributed 100% of the equity interests in Enogex to the Partnership in exchange for common units and, for OGE Energy only, interests in our general partner. The transaction was considered a business combination for accounting purposes, with the Partnership considered the acquirer of Enogex. Subsequent to May 1, 2013, the financial and operating data of the Partnership are consolidated to reflect the acquisition of Enogex and the retention of certain assets and liabilities by CenterPoint Energy.

	Year Ended December 31,				
	2014	2013	2012	2011	2010
	(In millions, except for unit, per unit and operating data)				
Results of Operations Data:					
Revenues	$3,367	$2,489	$952	$932	$871
Cost of goods sold, excluding depreciation and amortization	1,914	1,313	129	101	98
Operation and maintenance	527	429	267	263	233
Depreciation and amortization	276	212	106	91	77
Impairments	8	12	—	—	—
Taxes other than income	56	54	34	37	37
Operating income	586	469	416	440	426
Interest expense	(70)	(67)	(85)	(90)	(83)
Equity in earnings of equity method affiliates	20	15	31	31	29
Interest income—affiliated companies	—	9	21	14	9
Step acquisition gain	—	—	136	—	—
Other, net	(1)	—	—	—	(2)
Income before income taxes	535	426	519	395	379
Income tax expense (benefit)	2	(1,192)	203	163	155
Net income	$533	$1,618	$316	$232	$224
Less: Net income attributable to noncontrolling interest	3	3	—	—	—
Net income attributable to Enable Midstream Partners, LP	$530	$1,615	$316	$232	$224
Limited partners' interest in net income attributable to Enable Midstream Partners, LP(1)	$530	$289			
Basic and diluted earnings per common limited partner unit(1)(2)	$1.29	$0.74			
Basic and diluted earnings per subordinated limited partner unit(3)	$1.28				
Distributions declared per unit(4)	$0.4534	$0.6086			
Distributions declared per unit(5)	$0.8577				
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$9,582	$8,990	$4,705	$4,070	$3,876
Total assets	11,837	11,232	6,482	5,796	5,463
Long-term debt, including current portion	2,544	2,483	1,762	1,568	1,671
Enable Midstream Partners, LP Partners’ Capital	8,792	8,148	3,215	2,898	2,666

Table of Contents

	Year Ended December 31,				
	2014	2013	2012	2011	2010
	(In millions, except for unit, per unit and operating data)				
Cash Flow Data:					
Net cash flows provided by (used in):					
Operating activities	$769	$648	$451	$662	$308
Investing activities	(815)	(140)	(645)	(560)	(800)
Financing activities	(50)	(400)	194	(102)	492
Other Financial Data:					
Gross margin	$1,453	$1,176	$823	$831	$773
Adjusted EBITDA	$868	$729	$561	$570	$543
Distributable cash flow	$622				
Operating Data:					
Gathered volumes—TBtu	1,221	1,113	874	794	647
Gathered volumes—TBtu/d	3.34	3.05	2.39	2.17	1.77
Natural gas processed volumes—TBtu	569	397	73	37	57
Natural gas processed volumes—TBtu/d	1.56	1.09	0.20	0.10	0.16
NGLs produced—MBbl/d[6]	66.74	44.51	—	—	—
NGLs sold—MBbl/d[6][8]	68.67	44.91	0.25	0.09	0.12
Condensate sold—MBbl/d	4	2	—	—	—
Crude Oil - Gathered volumes—MBbl/d[7]	4	—	—	—	—
Transported volumes—TBtu	1,808	1,608	1,378	1,596	1,704
Transportation volumes—TBtu/d	4.95	4.41	3.76	4.37	4.67
Interstate firm contracted capacity—Bcf/d	7.73	8.01	7.94	8.12	8.88
Intrastate average deliveries—TBtu/d	1.61	1.58	—	—	—

(1) Limited partners' interest in net income attributable to Enable Midstream Partners, LP and basic and diluted earnings per unit reflect net income attributable to Enable Midstream Partners, LP subsequent to its formation as a limited partnership on May 1, 2013, as no limited partner units were outstanding prior to this date.

(2) Historical basic and diluted earnings per common limited partner unit reflects the 1 for 1.279082616 reverse unit split effected on March 25, 2014.

(3) Basic and diluted earnings per subordinated unit reflect net income attributable to the Partnership for periods subsequent to its Offering, as no subordinated units were outstanding prior to this date.

(4) Distributions attributable to periods prior to the Offering are in accordance with the First Amended and Restated Agreement of Limited Partnership. Distributions declared per unit prior to the Offering relate to common units, as no subordinated units were outstanding prior to the date of the Offering.

(5) Distributions attributable to periods subsequent to the Offering are in accordance with the Second Amended and Restated Agreement of Limited Partnership. Distributions declared per unit relate to common and subordinated units.

(6) Excludes condensate.

(7) Initial operation of our crude oil gathering system began on November 1, 2013.

(8) NGLs sold includes volumes of NGLs withdrawn from inventory or purchased for system balancing purposes.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with our combined and consolidated financial statements and the related notes included herein. 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.

Table of Contents

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 service primarily to natural gas producers, utilities and industrial customers.

Our natural gas gathering and processing assets are located in four states and serve natural gas production from shale developments in the Anadarko, Arkoma and Ark-La-Tex basins. We also own a crude oil gathering business in the Bakken Shale formation of the Williston Basin that commenced initial operations in November 2013. Our natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

We were formed in May 2013 as a limited partnership among CenterPoint Energy, OGE Energy and ArcLight. As of December 31, 2014, our portfolio of energy infrastructure assets included approximately 11,900 miles of gathering pipelines, 12 major processing plants with approximately 2.1 Bcf/d of processing capacity, approximately 7,900 miles of interstate pipelines (including SESH), approximately 2,300 miles of intrastate pipelines and eight storage facilities providing approximately 87.5 Bcf of storage capacity.

Our Operations

Our gathering and processing assets include approximately 11,900 miles of natural gas gathering pipelines in the Anadarko, Arkoma and Ark-La-Tex basins with approximately 853,000 horsepower of compression and 12 natural gas processing plants with approximately 2.1 Bcf/d of processing capacity and 2.1 Bcf/d of treating capacity as of December 31, 2014. We provide gathering, compression, treating, dehydration, processing and NGL fractionation for producers who are active in the areas in which we operate. For the year ended December 31, 2014, our assets gathered an average of approximately 3.34 TBtu/d of natural gas. For the year ended December 31, 2014, we processed approximately 1.56 TBtu/d of natural gas and produced approximately 66.74 MBbl/d of NGLs. We also have a crude oil gathering business in the Bakken Shale formation, principally located in the Williston Basin, that commenced initial operations in November 2013.

We provide fee-based interstate and intrastate transportation and storage services across nine states. We own and operate approximately 7,900 miles (including SESH) of interstate transportation pipelines with average firm contracted capacity of 7.73 Bcf/d (excluding SESH), for the year ended December 31, 2014. In addition, we own and operate approximately 2,300 miles of intrastate transportation pipelines with average aggregate throughput of 1.61 TBtu/d for the year ended December 31, 2014. We also own and operate eight natural gas storage facilities with approximately 87.5 Bcf of aggregate capacity and approximately 1.9 Bcf/d of aggregate daily deliverability as of December 31, 2014.

For the year ended December 31, 2014, approximately 72% of our gross margin was generated from contracts that are fee-based, and approximately 50% of our gross margin was attributable to fees associated with firm contracts or contracts with minimum volume commitment features.

The following table shows the components of our gross margin for the year ended December 31, 2014.

	Fee-Based Demand/ Commitment/ Guaranteed Return	Volume Dependent	Commodity-Based	Total
Year Ended December 31, 2014				
Gathering and Processing Segment	26 %	33 %	41 %	100 %
Transportation and Storage Segment	82 %	6 %	12 %	100 %
Partnership Weighted Average	50 %	22 %	28 %	100 %

Table of Contents

How We Evaluate Our Operations

We use a variety of financial and operational metrics to analyze our performance. We view these metrics as important factors in evaluating our profitability and review these measurements on at least a monthly basis for consistency and trend analysis. These metrics are significant factors in assessing our operating results and profitability and include: (i) throughput volumes; (ii) gross margin; (iii) operation and maintenance expenses; (iv) Adjusted EBITDA and (v) distributable cash flow.

Throughput Volumes

The volume of natural gas that we gather, process, transport and store depends significantly on the level of production from natural gas wells connected to our systems. Aggregate production volumes are impacted by the overall amount of drilling and completion activity, as production must be maintained or increased by new drilling or other activity, because the production rate of a natural gas well declines over time. Producers' willingness to engage in new drilling is determined by a number of factors, the most important of which are the prevailing and projected prices of natural gas, NGLs, and crude oil, the cost to drill and operate a well, the availability and cost of capital and environmental and government regulations. We generally expect the level of drilling to positively correlate with long-term trends in commodity prices. Similarly, production levels nationally and regionally generally tend to positively correlate with drilling activity.

To maintain and increase gathering throughput volumes on our systems, we must continue to contract our capacity to shippers, including producers and marketers. Our transportation and storage systems compete for customers based on the type of service a customer needs, operating flexibility, receipt and delivery points and geographic flexibility and available capacity and price. We actively monitor customer activity in the areas served by our systems to pursue new supply opportunities. To maintain and increase our transportation and storage volumes, we must continue to contract our capacity to shippers, including producers, marketers, LDCs, power generators and end-users.

Gross Margin

We view gross margin as an important performance measure of the core profitability of our business, as well as our operating performance as compared to that of other companies in our industry, without regard to financing methods, historical cost basis, capital structure or the impact of fluctuating commodity prices. We define gross margin as total revenues minus costs of goods sold, excluding depreciation and amortization. Gross margin allows us to make a meaningful comparison of the operating results between our fee-based revenues, and our commodity-based contracts which involve the purchase or sale of natural gas, NGLs, and/or crude oil. In addition, gross margin allows us to make a meaningful comparison of the results of our commodity-based activities across different commodity price environments because it measures the spread between the product sales price and cost of products sold. Please read "—Results of Operations" below.

Operation and Maintenance Expenses

We seek to maximize the profitability of our operations by effectively managing operation and maintenance expenses. These expenses are comprised primarily of labor expenses, lease costs, utility costs, insurance premiums and repairs and maintenance expenses. These expenses generally remain relatively stable across broad ranges of throughput volumes but can fluctuate from period to period depending on the mix of activities performed during that period and the timing of these expenses. We seek to manage our maintenance expenditures on our assets by scheduling maintenance over time to avoid significant variability in our maintenance expenditures and minimize their impact on our system operations and cash flow.

The levels of exploration, development and production activities impact competition for personnel and equipment. Increased competition could place upward pressure on the prices we pay for labor, supplies and miscellaneous equipment. To the extent we are unable to procure necessary services or offset higher costs, should they occur, our operating results will be negatively impacted.

Adjusted EBITDA and Distributable Cash Flow

We define Adjusted EBITDA 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. Distributable cash flow will not reflect changes in working capital balances. Please read “—Non-GAAP Financial Measures” below.

Note About Non-GAAP Financial Measures

Gross margin, Adjusted EBITDA and distributable cash flow are not financial measures presented in accordance with GAAP. Management believes that the presentation of these non-GAAP financial measures will provide useful information to investors in assessing our financial condition and results of operations.

Revenue is the GAAP measure most directly comparable to gross margin, and net income attributable to controlling interest and net cash provided by operating activities are the GAAP measures most directly comparable to Adjusted EBITDA and distributable cash flow. Our non-GAAP financial measures should not be considered as alternatives to the most directly comparable GAAP financial measure. Each of these non-GAAP financial measures has important limitations as an analytical tool because it excludes some but not all items that affect the most directly comparable GAAP financial measure. Gross margin, Adjusted EBITDA and distributable cash flow should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP. Because gross margin, Adjusted EBITDA and distributable cash flow may be defined differently by other companies in our industry, our definitions of these non-GAAP financial measures may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

Management compensates for the limitations of gross margin, Adjusted EBITDA and distributable cash flow as analytical tools by reviewing the comparable GAAP measures, understanding the differences between gross margin, Adjusted EBITDA and distributable cash flow, on the one hand, and revenue, net income and net cash provided by operating activities, on the other hand, and incorporating this knowledge into its decision-making processes. Management believes that investors benefit from having access to the same financial measures that our management uses in evaluating our operating results. For a reconciliation of gross margin, Adjusted EBITDA and distributable cash flow to their most directly comparable financial measures calculated and presented in accordance with GAAP, please read “—Non-GAAP Financial Measures” below.

Items Affecting the Comparability of Our Financial Results

Our future results of operations may not be comparable to our historical results of operations for the reasons described below.

Formation of Partnership. For accounting purposes, we treat the formation of our partnership on May 1, 2013 as an acquisition, with the Partnership as the acquirer of Enogex. As a result, our historical results of operations for periods prior to May 1, 2013 do not include the results of Enogex's operations.

Operation and Maintenance Expenses. We have entered into services agreements with each of CenterPoint Energy and OGE Energy pursuant to which they perform certain administrative services for us that are generally consistent with the level and type of services they provided to each of their respective businesses prior to our formation. These services include accounting, finance, legal, risk management, information technology and human resources. We are required to reimburse CenterPoint Energy and OGE Energy for their direct expenses or, where the direct expenses cannot reasonably be determined, an allocated cost as set forth in the agreements. Our reimbursement obligations are capped at amounts set forth in our annual budget. The initial term of the services agreements ends in May 2016, after which date they continue on a year-to-year basis unless terminated by us upon 90 days’ notice.

Historically, our general and administrative expenses included direct monthly charges for the management and operation of our logistics assets and certain expenses allocated by our sponsors for general corporate services, such as treasury, accounting and legal services. These expenses were charged or allocated to us based on conventions accepted by the regulators of CenterPoint Energy's and OGE Energy's regulated utility assets. For additional information, please see Note 13 to the Combined and Consolidated Financial Statements for the years ended December 31, 2014, 2013 and 2012.

Income Tax Expenses. Prior to May 1, 2013, our assets were included in CenterPoint Energy's consolidated federal income tax returns, which were taxed at the entity level as a C corporation. Following our formation, we are treated as a partnership for federal income tax purposes, with each partner being separately taxed on its share of taxable income; therefore, there is no income tax expense in our financial statements subsequent to May 1, 2013 (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiary). As a result of the conversion to a limited partnership, we recorded a one-time income tax benefit of $1.24 billion in the year ended December 31, 2013.

Financing. Upon our formation, we entered into our $1.05 billion three-year Term Loan Facility, the proceeds of which were used to repay $1.05 billion of intercompany indebtedness owed to CenterPoint Energy. In addition, upon our formation, we entered into a $1.4 billion five-year revolving credit facility. Initial advances under the Revolving Credit Facility were used for general partnership purposes and to refinance the Enogex Revolving Credit Facility, which was terminated in connection with our formation,

Table of Contents

and existing indebtedness owing by Enogex to OGE Energy as of May 1, 2013.

In January 2014, we initiated our $1.4 billion commercial paper program. This program is used for general corporate purposes. Commercial paper issuances effectively reduce our borrowing capacity under our Revolving Credit Facility. In April 2014, the Partnership completed the Offering of 25,000,000 units and received net proceeds of $464 million. The Partnership retained the net proceeds of the Offering for general partnership purposes, including the funding of expansion capital expenditures, and to pre-fund demand fees expected to be incurred over the next three years relating to certain expiring transportation and storage contracts. On May 27, 2014, the Partnership completed the private offering of 2019 Notes, 2024 Notes and 2044 Notes, with registration rights. The Partnership received aggregate proceeds of $1.63 billion. Certain of the proceeds were used to repay the Term Loan Facility, and certain of the proceeds were used to repay the Enable Oklahoma $250 million variable rate term loan and the Enable Oklahoma $200 million 6.875% senior notes due July 15, 2014, and for general corporate purposes. See Note 10 for discussion of the repayment of the Enable Oklahoma $200 million 6.875% senior notes. A wholly owned subsidiary of CenterPoint Energy has guaranteed collection of the Partnership's obligations under the 2019 Notes and 2024 Notes, on an unsecured subordinated basis, subject to automatic release on May 1, 2016. Please read "—Liquidity and Capital Resources".

Cash Distributions. Our partnership agreement requires that we distribute to our unitholders quarterly all of our available cash. As a result, we expect to fund future capital expenditures primarily from external sources, including borrowings under our Revolving Credit Facility, issuances of commercial paper and future issuances of equity and debt securities.

General Trends and Outlook

We expect our business to continue to be affected by the key trends discussed below. 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.

Commodity Price Volatility

Prices of natural gas, crude oil and NGLs have historically experienced periods of significant volatility. Commodity price changes impact the commodity-based portion of our gross margin, our producer customers' decisions to drill and complete wells and our transportation and storage customers' decisions to contract capacity on our systems. Our results are also impacted by the price differentials between receipt and delivery points on our systems. We have attempted to mitigate the impact of commodity prices on our business by entering into hedges, focusing on contracting fee-based business, and converting existing commodity-based contracts to fee-based contracts. Recently, the prices of crude oil, NGLs and natural gas have declined significantly. Should lower commodity prices persist, our future volumes and cash flows may be negatively impacted. For additional information regarding our commodity price risk, see Item 7A. "Quantitative and Qualitative Disclosures About Market Risk - Commodity Price Risk."

Growth in Production of U.S. Shale Plays

Over the past several years, there has been a fundamental shift in U.S. natural gas and crude oil production towards tight gas formations and shale plays. The emergence of these plays and advancements in technology have been crucial factors that have allowed producers to efficiently extract significant volumes of natural gas and crude oil. Recently, declining crude oil and natural gas liquids prices have resulted in current and anticipated decreases in crude oil and natural gas drilling activity. Should lower prices and producer activity persist for a sustained period, our future volumes and cash flows may be negatively impacted.

Natural Gas Supply and Demand Dynamics

Natural gas continues to be a critical component of energy supply and demand in the United States. Over the long term, management believes that the prospects for continued natural gas demand are favorable and will be driven by population and economic growth, as well as the continued displacement of coal-fired electricity generation by natural gas-fired electricity generation due to the low prices of natural gas and stricter government environmental regulations on the mining and burning of coal. According to the EIA, demand for natural gas in the electric power sector is projected to increase from approximately 9.3 Tcf in 2012 to approximately 11.2 Tcf in 2040, with a portion of the growth attributable to the retirement of 50 gigawatts of coal-fired capacity by 2020. The EIA also projects that natural gas consumption in the industrial sector will be higher due to the

Table of Contents

rejuvenation of the industrial sector as it benefits from low natural gas prices. However, the EIA expects growth in natural gas consumption for power generation and in the industrial sector to be partially offset by decreased usage in the residential sector. Management believes that increasing consumption of natural gas over the long term will continue to drive demand for our natural gas gathering, processing, transportation and storage services.

Capital Market Volatility

We depend on access to the capital markets to fund our expansion capital expenditures. Historically, unit prices of midstream master limited partnerships have experienced periods of volatility. In addition, because our common units are yield-based securities, rising market interest rates could impact the relative attractiveness of our common units to investors. As a result of capital market volatility, we may be unable to issue equity or debt on satisfactory terms, or at all, which may limit our ability to expand our operations or make future acquisitions.

Regulatory Compliance

The regulation of gathering and transmission pipelines, storage and related facilities by FERC and other federal and state regulatory agencies, including the DOT, has a significant impact on our business. For example, the DOT's Pipeline and Hazardous Materials Safety Administration, or PHMSA, has established pipeline integrity management programs that require more frequent inspections of pipeline facilities and other preventative measures, which may increase our compliance costs and increase the time it takes to obtain required permits. Additionally, increased regulation of oil and natural gas producers, including regulation associated with hydraulic fracturing, could reduce regional supply of oil and natural gas and therefore throughput on our gathering systems. For more information see Item 1. "Business-Rate and Other Regulation."

Planned Workforce Reductions

On February 16, 2015, management of the Partnership announced to its employees that during 2015, the Partnership plans to reduce its current workforce by approximately 10% and consolidate certain administrative functions to its Oklahoma City, Oklahoma and Houston, Texas offices in order to reduce costs and improve efficiency. Impacted employees will be provided with severance payments, the terms of which have yet to be finalized. While the intent of these actions is to reduce Operating and Maintenance expense over the long term, the future cost savings have not yet been determined.

Results of Operations

The historical financial information included below reflects the combined assets, liabilities and operations of the entities comprising CenterPoint Energy's reportable segments for periods ending prior to May 1, 2013 and the consolidated assets, liabilities and operations of these reportable segments and Enogex for periods ending on or after May 1, 2013. With respect to periods ending prior to May 1, 2013, we refer to CenterPoint Energy's Interstate Pipelines segment as our Transportation and Storage segment and CenterPoint Energy's Field Services segment as our Gathering and Processing segment.

December 31, 2014	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			

Revenues	$2,424	$1,577	$(634)	$3,367
Cost of goods sold (excluding depreciation and amortization)	1,585	961	(632)	1,914
Gross margin on revenues	839	616	(2)	1,453
Operation and maintenance	297	232	(2)	527
Depreciation and amortization	160	116	—	276
Impairment	8	—	—	8
Taxes other than income tax	25	31	—	56
Operating income	$349	$237	$—	$586
Equity in earnings of equity method affiliates	$—	$20	$—	$20

December 31, 2013	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Revenues	$1,740	$1,149	$(400)	$2,489
Cost of goods sold (excluding depreciation and amortization)	1,075	636	(398)	1,313
Gross margin on revenues	665	513	(2)	1,176
Operation and maintenance	222	209	(2)	429
Depreciation and amortization	117	95	—	212
Impairment	12	—	—	12
Taxes other than income tax	20	34	—	54
Operating income	$294	$175	$—	$469
Equity in earnings of equity method affiliates	$—	$15	$—	$15

December 31, 2012	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Revenues	$502	$502	$(52)	$952
Cost of goods sold (excluding depreciation and amortization)	124	55	(50)	129
Gross margin on revenues	378	447	(2)	823
Operation and maintenance	114	155	(2)	267
Depreciation and amortization	50	56	—	106
Taxes other than income tax	5	29	—	34
Operating income	$209	$207	$—	$416
Equity in earnings of equity method affiliates	$5	$26	$—	$31

	Year Ended December 31,		
	2014	2013	2012
Operating Data:			
Gathered volumes—TBtu	1,221	1,113	874
Gathered volumes—TBtu/d[1]	3.34	3.05	2.39
Natural gas processed volumes—TBtu	569	397	73
Natural gas processed volumes—TBtu/d[1]	1.56	1.09	0.20
NGLs produced—MBbl/d[1][2]	66.74	44.51	—
NGLs sold—MBbl/d[1][2][4]	68.67	44.91	0.25
Condensate sold—MBbl/d[1]	4.38	1.88	—
Crude Oil - Gathered volumes—MBbl/d[3]	3.64	—	—
Transported volumes—TBtu	1,808	1,608	1,378
Transportation volumes—TBtu/d[1]	4.95	4.41	3.76
Interstate firm contracted capacity—Bcf/d[1]	7.73	8.01	7.94
Intrastate average deliveries—TBtu/d[1]	1.61	1.58	—

---

(1) 2013 daily averages are computed utilizing a 365 day convention, and are not computed using a weighted average convention for the acquisition of Enogex.

(2) Excludes condensate.

(3) Initial operation of our crude oil gathering system began on November 1, 2013.
(4) NGLs sold includes volumes of NGLs withdrawn from inventory or purchased for system balancing purposes.

Table of Contents

Gathering and Processing

2014 compared to 2013. Our gathering and processing segment reported operating income of $349 million in the year ended December 31, 2014 compared to $294 million in the year ended December 31, 2013. Operating income increased $55 million primarily from increased gross margin of $174 million and a decrease in impairments of $4 million, partially offset by an increase in operation and maintenance expenses of $75 million, an increase in depreciation and amortization of $43 million, and an increase in taxes other than income tax of $5 million, during the year ended December 31, 2014.

Our gathering and processing segment gross margin increased $174 million primarily due to the 2013 acquisition of Enogex, resulting in an increase to gross margin of $138 million, higher average natural gas prices of $9 million, higher processing margin of $35 million due to increased processed volumes in the Anadarko and Ark-La-Tex basins, unrealized gains on condensate derivatives of $5 million, and the addition of gross margin on our crude oil gathering business of $5 million, partially offset by higher cost of goods sold on third party measurement and communication services of $7 million and decreased gathered volumes in the Ark-La-Tex and Arkoma basins of $11 million, net of minimum volume payments.

Our gathering and processing segment operation and maintenance expenses increased $75 million primarily due to the 2013 acquisition of Enogex, which contributed $51 million of operation and maintenance expenses, as well as an increase in payroll-related expenses of $6 million from increased head count to support business growth, an increase in integration costs of $6 million, an increase in general operating and maintenance expenses of $11 million to support and operate new assets, a write down of materials and supplies inventory of $4 million and a loss on sale of assets of $1 million, partially offset by $4 million due to lower third party measurement and communications services expenses.

Our gathering and processing segment depreciation and amortization expense increased $43 million due to the depreciation on assets related to the 2013 acquisition of Enogex of $31 million and $12 million due to depreciation on assets placed in service.

Our gathering and processing segment recognized impairments of $8 million and $12 million in the years ended December 31, 2014 and 2013, respectively. Due to the cancellation of services by additional customers during 2014, management reassessed the carrying value of the Service Star business line, which resulted in the 2014 impairment. Therefore, the $4 million decrease was primarily due to the decrease in the Service Star impairment of $5 million, offset by additional impairments of other assets of $1 million in 2014.

Our gathering and processing segment taxes other than income tax increased $5 million due to increased ad valorem taxes as a result of additional assets in service related to the 2013 acquisition of Enogex of $4 million, and other additional assets placed in service of $4 million. These increases were partially offset by the favorable settlement of a state and local tax dispute for $3 million less than the previously recognized reserve.

2013 compared to 2012. Our gathering and processing segment reported operating income of $294 million in the year ended December 31, 2013 compared to $209 million in the year ended December 31, 2012. Operating income increased $85 million primarily from increased gross margin of $287 million, partially offset by an increase in operation and maintenance expenses of $108 million, an increase in depreciation and amortization of $67 million, a $12 million impairment of Service Star, and taxes other than income tax of $15 million, during the year ended December 31, 2013.

Our gathering and processing segment gross margin increased $287 million primarily due to the acquisitions of Enogex, Waskom, and other facilities, resulting in an increase to margins of $242 million, $24 million and $9 million, respectively, for an aggregate $275 million increase attributable to acquisitions, higher natural gas prices of $21 million, partially offset by a decline in customers of $10 million.

Our gathering and processing segment operation and maintenance expenses increased $108 million primarily due to the 2013 acquisition of Enogex, which contributed $96 million to operation and maintenance expenses in the year ended December 31, 2013. The increase also reflects a $10 million increase in general and administrative expenses, payroll expenses and benefits to support growth as well as a $2 million increase in contract and service expenses.

Our gathering and processing segment depreciation and amortization increased $67 million due to the additional assets placed in service from the 2013 acquisition of Enogex, which resulted in an increase of $55 million, as well as a $12 million increase as a result of asset additions in the year ended December 31, 2013.

Table of Contents

Our gathering and processing segment impairment increased $12 million as there was a $12 million impairment of Service Star during the year ended December 31, 2013.

Our gathering and processing segment taxes other than income tax increased $15 million due to increased ad valorem taxes as a result of assets placed in service from the 2013 acquisition of Enogex and other asset additions of $7 million and $4 million, respectively, as well as a $2 million sales and use tax adjustment related to 2012.

Our gathering and processing segment recorded equity in earnings of equity method affiliates of $0 million, $0 million, and $5 million for the years ended December 31, 2014, 2013 and 2012, respectively, from its 50% interest in Waskom. These amounts are included in equity in earnings of equity affiliates under the Other Income (Expense) caption in the Combined and Consolidated Statements of Income for the years ended December 31, 2014, 2013 and 2012. Beginning August 1, 2012, financial results for Waskom are consolidated (combined) and included in operating income.

Transportation and Storage

2014 compared to 2013. Our transportation and storage segment reported operating income of $237 million in the year ended December 31, 2014 compared to $175 million in the year ended December 31, 2013. Operating income increased $62 million primarily resulting from an increase in gross margin of $103 million and a decrease in taxes other than income tax of $3 million, partially offset by an increase of $23 million in operation and maintenance expenses, as well as an increase of $21 million in depreciation and amortization expense during the year ended December 31, 2014.

Our transportation and storage segment gross margin increased $103 million primarily due to the 2013 acquisition of Enogex, which contributed $47 million to gross margin, as well as an increase in unrealized gains on natural gas derivatives of $32 million, an increase from system optimization activities of $12 million, an increase from operational synergies of $3 million, an increase from off-system transportation revenues of $6 million, higher rates on transportation services for local distribution companies of $9 million, and higher other firm transportation revenues of $4 million, partially offset by a decrease in storage demand fees of $9 million and balancing services of $1 million.

Our transportation and storage segment operation and maintenance expenses increased $23 million due to the 2013 acquisition of Enogex, which contributed $19 million to operation and maintenance expenses, an increase in payroll-related expense of $23 million from increased head count to support business growth, an increase in general operating and maintenance expenses of $5 million to support and operate new assets, and a write down of materials and supplies inventory of $2 million, partially offset by a decrease in relocation costs of $4 million, a decrease in allocated corporate service costs of $15 million, and a litigation settlement of $5 million in 2013, offset in 2014 by $2 million of insurance proceeds.

Our transportation and storage segment depreciation and amortization expense increased $21 million primarily due to the additional assets in service related to the 2013 acquisition of Enogex of $16 million, MRT rate case impact of $1 million and asset additions of $4 million.

Our transportation and storage segment taxes other than income tax decreased $3 million due to reduced ad valorem taxes on intangible assets of $6 million, partially offset by the 2013 acquisition of Enogex, which contributed $3 million.

Our transportation and storage segment recorded equity in earnings of equity method affiliates of $20 million and $15 million for the years ended December 31, 2014 and 2013, respectively, from our interest in SESH. The $5 million increase is attributable to the 24.95% interest in SESH contributed by CenterPoint Energy on May 30, 2014 to the

Partnership.

2013 compared to 2012. Our transportation and storage segment reported operating income of $175 million in the year ended December 31, 2013 compared to $207 million in the year ended December 31, 2012. Operating income decreased $32 million primarily resulting from an increase of $54 million in operation and maintenance expenses, a $39 million increase in depreciation and amortization, and a $5 million increase in taxes other than income tax. The decrease in operating income was partially offset by an increase in gross margin of $66 million for the year ended December 31, 2013.

Our transportation and storage segment gross margin increased $66 million primarily due to the 2013 acquisition of Enogex, which contributed $84 million to gross margin, and our 10-year agreement with a natural gas distribution affiliate, entered into in 2010, which contributed an increase in gross margin by $7 million in the year ended December 31, 2013. These increases were partially offset by a decline in gross margin attributable to lower volumes and lower price differentials, which negatively impacted margins on ancillary services by $15 million and off-system transportation revenues by $8 million.

Table of Contents

Our transportation and storage segment operation and maintenance expenses increased $54 million primarily due to the 2013 acquisition of Enogex, which contributed $38 million to operation and maintenance expenses and $6 million in integration costs in the year ended December 31, 2013. The increases in operation and maintenance expenses also reflect a litigation settlement of $5 million and an increase in corporate service costs provided by affiliates of $4 million (excluding a $1 million increase in corporate services costs incurred by Enable Oklahoma) recognized in the year ended December 31, 2013.

Our transportation and storage segment depreciation and amortization increased $39 million primarily due to the additional assets in service from the 2013 acquisition of Enogex, which resulted in an increase of $32 million. Additionally, depreciation and amortization increased $4 million due to MRT's rate case settlement true-up as well as an additional $3 million related to asset additions in the year ended December 31, 2013.

Our transportation and storage segment taxes other than income tax increased $5 million primarily due to the 2013 acquisition of Enogex.

Equity Earnings. Our transportation and storage segment recorded equity in earnings of equity method affiliates of $15 million and $26 million for the years ended December 31, 2013 and 2012, respectively, from our interest in SESH. The 2013 decrease in equity earnings compared to 2012 was a result of the Partnership distributing a 25.05% interest in SESH to CenterPoint Energy.

Combined and Consolidated Interim Information

	Year Ended December 31,		
	2014	2013	2012
	(In millions)		
Operating Income	$586	$469	$416
Other Income (Expense):			
Interest expense	(70)	(67)	(85)
Equity in earnings of equity method affiliates	20	15	31
Interest income—affiliated companies	—	9	21
Step acquisition gain	—	—	136
Other, net	(1)	—	—
Total Other Income (Expense)	(51)	(43)	103
Income Before Income Taxes	535	426	519
Income tax expense (benefit)	2	(1,192)	203
Net Income	$533	$1,618	$316
Less: Net income attributable to noncontrolling interest	3	3	—
Net Income attributable to Enable Midstream Partners, LP	$530	$1,615	$316

	Year Ended December 31,		
	2014	2013	2012
	(In millions)		
Other Financial Data:			
Gross Margin [(1)]	$1,453	$1,176	$823
Adjusted EBITDA [(1)]	868	729	561
Distributable cash flow [(1)]	622	496	366

(1) Gross margin, Adjusted EBITDA and distributable cash flow are defined and reconciled to their most directly comparable financial measures calculated and presented below under the caption Non-GAAP Financial Measure.

2014 compared to 2013

Net Income attributable to the Partnership. We reported net income attributable to the Partnership of $530 million and $1,615 million in the years ended December 31, 2014 and 2013, respectively. The decrease in net income attributable to the Partnership of $1,085 million was primarily attributable to the 2013 recognition of a $1,194 million income tax benefit upon conversion to a limited partnership, net of taxes incurred prior to the conversion, an increase in other income and expense related to the loss on extinguishment of debt of $1 million, an increase in interest expense of $3 million and a decrease in interest income of $9 million as a result of the reduction in notes receivable. These increases were partially offset by an increase in equity earnings in equity method affiliates of $5 million (discussed by reportable segment above) and an increase in operating income of $117 million inclusive of the $50 million impact of the 2013 acquisition of Enogex discussed by segment above.

Interest Expense. Interest expense increased $3 million, primarily due to a $10 million increase in interest expense incurred on the debt assumed with the 2013 acquisition of Enogex, partially offset by a decrease of $7 million related to lower interest rates on the Partnership's other outstanding debt.

Income Tax Expense. Effective May 1, 2013, upon conversion to a limited partnership, the Partnership’s earnings are no longer subject to income taxes (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiary). As a result of the conversion to a partnership, we recognized our outstanding current income tax liabilities and deferred income tax assets and liabilities by recording an income tax benefit of $1,194 million, net of taxes incurred prior to the conversion. Consequently, the Combined and Consolidated Statement of Income for the year ended December 31, 2014 does not include an income tax provision (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiary).

2013 compared to 2012

Net Income attributable to the Partnership. We reported net income attributable to the Partnership of $1,615 million and $316 million in the years ended December 31, 2013 and 2012, respectively. The increase in net income attributable to the Partnership of $1,299 million was primarily attributable to the acquisition of Enogex on May 1, 2013 ($74 million), a positive impact from income taxes of $1,395 million, and a decrease in interest expense of $18 million (excluding impact of interest on debt acquired with Enogex) offset by a decrease in equity earnings of equity method affiliates of $16 million and a decrease in interest income of $12 million as a result of a reduction in notes receivable in the year ended December 31, 2013. Additionally, we recorded a step acquisition gain of $136 million in the year ended December 31, 2012 attributed to the acquisition of the outstanding 50% interest in Waskom.

Interest Expense. Interest expense decreased $18 million primarily due to lower interest rates on the Term Loan Facility and revolving credit facilities which were effective May 1, 2013, offset by an increase in borrowings (excluding the impact of debt acquired with Enogex) and in interest expense incurred on the debt assumed with the 2013 acquisition of Enogex of $15 million.

Income Tax Expense. Effective May 1, 2013, we converted to a limited partnership and our earnings were no longer subject to income taxes (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiary). As a result of the conversion to a partnership, we recognized our outstanding current income tax liabilities and deferred income tax assets and liabilities by recording an income tax benefit of $1,192 million. Consequently, the Combined and Consolidated Statement of Income for the year ended December 31, 2013 does not include an income tax provision for income earned on or after May 1, 2013 (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiary).

Non-GAAP Financial Measures

The Partnership has included the non-GAAP financial measures gross margin, Adjusted EBITDA and distributable cash flow in this report based on information in its combined and consolidated financial statements.

Gross margin, Adjusted EBITDA and distributable cash flow 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 revenues, Adjusted EBITDA and distributable cash flow to net income attributable to controlling interest, and Adjusted EBITDA to net cash provided by operating activities, the most directly comparable GAAP financial measures, on a historical basis, as applicable, for each of the periods indicated. The Partnership believes that the

Table of Contents

presentation of gross margin, Adjusted EBITDA and distributable cash flow provides information useful to investors in assessing its financial condition and results of operations. Gross margin, Adjusted EBITDA and distributable cash flow should not be considered as alternatives to net income, operating income, revenue, cash from operations or any other measure of financial performance or liquidity presented in accordance with GAAP. Gross margin, Adjusted EBITDA and distributable cash flow have important limitations as an analytical tool because they exclude some but not all items that affect the most directly comparable GAAP measures. Additionally, because gross margin, Adjusted EBITDA and distributable cash flow may be defined differently by other companies in the Partnership's industry, its definitions of gross margin, Adjusted EBITDA and distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

	Year Ended December 31,		
	2014	2013	2012
	(In millions)		
Reconciliation of Gross Margin to Revenue:			
Revenues	$3,367	$2,489	$952
Cost of goods sold, excluding depreciation and amortization	1,914	1,313	129
Gross margin	$1,453	$1,176	$823
Reconciliation of Adjusted EBITDA and distributable cash flow to net income attributable to controlling interest:			
Net income attributable to Enable Midstream Partners, LP	$530	$1,615	$316
Add:			
Depreciation and amortization expense	276	212	106
Interest expense, net of interest income	70	58	64
Income tax expense (benefit)	2	(1,192)	203
EBITDA	$878	$693	$689
Add:			
Loss on extinguishment of debt	4	—	—
Distributions from equity method affiliates [1]	23	24	39
Other non-cash losses	22	15	—
Impairment	8	12	—
Less:			
Other non-cash items	(47)	—	—
Equity in earnings of equity method affiliates	(20)	(15)	(31)
Step acquisition gain	—	—	(136)
Adjusted EBITDA	$868	$729	$561
Less:			
Adjusted interest expense, net [2]	(82)	(69)	(64)
Maintenance capital expenditures	(164)	(164)	(131)
Distributable cash flow	$622	$496	$366

Table of Contents

	Year Ended December 31,		
	2014	2013	2012
	(In millions)		
Reconciliation of Adjusted EBITDA to net cash provided by operating activities:			
Net cash provided by operating activities	$769	$648	$451
Interest expense, net of interest income	70	58	64
Net income attributable to noncontrolling interest	(3)	(3)	—
Income tax expense (benefit)	2	(1,192)	203
Deferred income tax (expense) benefit	(1)	1,194	(196)
Equity in earnings of equity method affiliates, net of distributions [1]	(3)	(9)	(8)
Impairment	(8)	(12)	—
Step acquisition gain	—	—	136
Other non-cash items	(12)	(1)	—
Changes in operating working capital which (provided) used cash:			
Accounts receivable	(53)	85	8
Accounts payable	140	(65)	6
Other, including changes in noncurrent assets and liabilities	(23)	(10)	25
EBITDA	$878	$693	$689
Add:			
Impairment	8	12	—
Loss on extinguishment of debt	4	—	—
Distributions from equity method affiliates (1)	23	24	39
Other non-cash losses	22	15	—
Less:			
Other non-cash items	(47)		
Equity in earnings of equity method affiliates	(20)	(15)	(31)
Step acquisition gain	—	—	(136)
Adjusted EBITDA	$868	$729	$561

(1) Excludes $198 million in special distributions for the return of investment in SESH for the year ended December 31, 2014.

(2) Adjusted interest expense, net excludes the effect of the amortization of the premium on Enogex’s fixed rate senior notes. This exclusion is the primary reason for the difference between “Interest expense, net” and “Adjusted interest expense, net.”

Liquidity and Capital Resources

The Partnership’s principal liquidity requirements are to finance its operations, fund capital expenditures and acquisitions, make cash distributions and satisfy any indebtedness obligations. We expect that our liquidity and capital resource needs will be met by cash on hand, operating cash flow, proceeds from commercial paper, borrowings under our revolving credit facility, debt issuances and the issuance of equity. Historically, our liquidity and capital resource needs have been met by these sources and, prior to 2014, contributions by CenterPoint Energy, OGE Energy and ArcLight. However, issuances of equity or debt in the capital markets, funds raised in the commercial paper markets and additional credit facilities may not be available to us on acceptable terms. Factors that contribute to our ability to raise capital through these channels depend on our financial condition, credit ratings and market conditions. Our ability to generate cash flow is subject to a number of factors, some of which are beyond our control. See Item 1A. "Risk Factors" for further discussion.

Table of Contents

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 December 31, 2014, we had a working capital deficit of $233 million due primarily to borrowings under our commercial paper program to manage the timing of cash flows for maintenance and expansion activity. We utilize the Commercial Paper Program and 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:

	Year Ended December 31,		
	2014	2013	2012
	(In millions)		
Net cash provided by operating activities	$769	$648	$451
Net cash (used in) provided by investing activities	(815)	(140)	(645)
Net cash provided by (used in) financing activities	(50)	(400)	194

Operating Activities

The increase of $121 million or 19%, in net cash provided by operating activities for the year ended December 31, 2014 as compared to the year ended December 31, 2013, is due to the impact of timing of payments and receipts on changes in assets and liabilities partially offset by:

- the acquisition of Enogex on May 1, 2013, which added $186 million in gross margin and $70 million in operation and maintenance expenses during the year ended December 31, 2014; and
- excluding the acquisition of Enogex:
- higher Gathering and Processing gross margin of $32 million;
- higher Transportation and Storage gross margin of $59 million; and
- higher payroll related expenses of $29 million and higher non-capital costs of $16 million, offset by lower integration costs of $9 million and other costs of $8 million, all within operation and maintenance expenses.

The increase of $197 million, or 44%, in net cash provided by operating activities for the year ended December 31, 2013 as compared to the year ended December 31, 2012 was primarily due to:

- the acquisition of Enogex on May 1, 2013, which added $326 million in gross margin and $134 million in operation and maintenance expenses during the year ended December 31, 2013; and
- excluding the acquisition of Enogex:
- higher Gathering and Processing gross margin of $44 million;
- lower Transportation and Storage gross margin of $17 million;
- integration costs of $8 million, higher payroll related expenses of $11 million and higher contracts and services expenses of $6 million, all within operation and maintenance expenses; and
- the impact of the timing of payments and receipts on changes in assets and liabilities.

Investing Activities

The increase of $675 million, or 482%, in net cash used in investing activities for the year ended December 31, 2014 as compared to the year ended December 31, 2013 was primarily due:

- higher gathering and processing capital expenditures of $299 million;
- the payment of $434 million on notes receivable-affiliated companies in 2013;
- investment in equity method affiliates of $189 million;

Table of Contents

- lower transportation and storage capital expenditures of $45 million; and
- distributions from equity method affiliates of $198 million in 2014.

The decrease of $505 million, or 78%, in net cash used in investing activities for the year ended December 31, 2013 as compared to the year ended December 31, 2012 was primarily due:

- flat gathering and processing capital expenditures, including acquisitions of $360 million in 2012;
- higher transportation and storage capital expenditures of $10 million; and
- the receipt of $514 million on notes receivable-affiliated companies.

Financing Activities

The decrease of $350 million in net cash used in financing activities for the year ended December 31, 2014 as compared to the year ended December 31, 2013 was primarily due to:

- decrease in gross borrowings under the Revolving Credit Facility of $1,011 million and decrease in gross repayments of $267 million;
- issuance of commercial paper of $253 million in 2014;
- decrease in notes payable-affiliated companies of $1,542 million;
- increase in capital contributions from partners of $421 million; and
- increase in distributions to partners of $346 million.

The increase of $594 million in net cash used in financing activities for the year ended December 31, 2013 as compared to the year ended December 31, 2012 was primarily due to:

- the net cash used in financing activities of $217 million for the year ended December 31, 2013 resulting from the financing transactions associated with our formation and the acquisition of Enogex on May 1, 2013, compared to net cash provided from notes payable-affiliated companies of $194 million for the year ended December 31, 2012; and
- the distribution of $183 million to partners in the year ended December 31, 2013.

Sources of Liquidity

At December 31, 2014, our sources of liquidity included:

- cash on hand;
- cash generated from operations;
- proceeds of commercial paper issuances and borrowings under our Revolving Credit facility; and
- capital raised through debt and equity markets

Revolving Credit Facility

On May 1, 2013, we entered into a $1.4 billion, five-year senior unsecured revolving credit facility (Revolving Credit Facility). As of December 31, 2014, there were no principal advances and $2 million in letters of credit outstanding under the Revolving Credit Facility. As of January 31, 2015, there were no principal advances and $2 million in letters of credit outstanding under the Revolving Credit Facility. However, as discussed below, commercial paper borrowings effectively reduce our borrowing capacity under this Revolving Credit Facility. As of January 31, 2015, $224 million was outstanding under our commercial paper program.

The Revolving Credit Facility permits outstanding borrowings to bear interest at the London Interbank Offered Rate (LIBOR) and/or an alternate base rate, at our election, plus an applicable margin. The applicable margin is based on our applicable credit ratings. As of December 31, 2014, the applicable margin for LIBOR-based borrowings under the

Revolving Credit Facility was 1.625% based on our credit ratings. In addition, the Revolving Credit Facility requires us to pay a fee on unused commitments. The commitment fee is based on our applicable credit rating from Moody's Investors Service, Inc., Standard & Poor's Ratings Services, a division of The McGraw-Hill Companies, and Fitch, Inc. As of December 31, 2014, the commitment fee under the

Table of Contents

Revolving Credit Facility was 0.25% per annum based on our credit ratings.

Advances under the Revolving Credit Facility are subject to certain conditions precedent, including the accuracy in all material respects of certain representations and warranties and the absence of any default or event of default. Initial advances under the Revolving Credit Facility were used for general partnership purposes and to refinance the Enogex Revolving Credit Facility, which was terminated in connection with our formation, and existing indebtedness owing by Enogex to OGE Energy as of May 1, 2013.

The Revolving Credit Facility contains a financial covenant requiring us to maintain a ratio of consolidated funded debt to consolidated EBITDA as defined under the Revolving Credit Facility as of the last day of each fiscal quarter of less than or equal to 5.00 to 1.00; provided that, for a certain period of time following the consummation by us or certain of our subsidiaries of any one or more related acquisitions with a purchase price of at least $50 million in the aggregate, the consolidated funded debt to consolidated EBITDA ratio as of the last day of each such fiscal quarter during such period would be permitted to be up to 5.50 to 1.00.

The Revolving Credit Facility also contains covenants that restrict us and certain subsidiaries in respect of, among other things, mergers and consolidations, sales of all or substantially all assets, incurrence of subsidiary indebtedness, incurrence of liens, transactions with affiliates, designation of subsidiaries as Excluded Subsidiaries (as defined in the Revolving Credit Facility), restricted payments, changes in the nature of their respective businesses and entering into certain restrictive agreements. Borrowings under the Revolving Credit Facility are subject to acceleration upon the occurrence of certain defaults, including, among others, payment defaults on such facility, breach of representations, warranties and covenants, acceleration of indebtedness (other than intercompany) of $100 million or more in the aggregate, change of control, nonpayment of uninsured money judgments in excess of $100 million, and the occurrence of certain ERISA and bankruptcy events, subject where applicable to specified cure periods.

Commercial Paper Program

We commenced a commercial paper program in January 2014, pursuant to which we are 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. As of December 31, 2014, $253 million was outstanding under our commercial paper program. As of January 31, 2015, $224 million was outstanding under our commercial paper program. Any reduction in our credit ratings could prevent us from accessing the commercial paper markets.

Promissory Notes Payable to Sponsor

Certain of the entities contributed to us by CenterPoint Energy on May 1, 2013 were obligated on approximately $363 million of indebtedness owed to a wholly owned subsidiary of CenterPoint Energy. As of December 31, 2014, the $363 million notes payable-affiliated companies bear an annual interest rate of 2.10% to 2.45% and are scheduled to mature in 2017.

Partnership Senior Notes

On May 27, 2014, the Partnership completed the private offering of the 2019 Notes, 2024 Notes and 2044 Notes, which include registration rights. The Partnership received aggregate proceeds of $1.63 billion. Certain of the proceeds were used to repay the Term Loan Facility, and certain of the proceeds were used to repay the Enable

Oklahoma $250 million variable rate term loan and the Enable Oklahoma $200 million 6.875% senior notes due July 15, 2014, and for general corporate purposes. See Note 10 for discussion of the repayment of the Enable Oklahoma $200 million 6.875% senior notes. A wholly owned subsidiary of CenterPoint Energy has guaranteed collection of the Partnership's obligations under the 2019 Notes and 2024 Notes, on an unsecured subordinated basis, subject to automatic release on May 1, 2016.

The indenture governing the 2019 Notes, 2024 Notes and 2044 Notes contains certain restrictions, including, among others, limitations on our ability and the ability of our principal subsidiaries to: (i) consolidate or merge and sell all or substantially all of our and our subsidiaries' assets and properties; (ii) create, or permit to be created or to exist, any lien upon any of our or our principal subsidiaries' principal property, or upon any shares of stock of any principal subsidiary, to secure any debt; and (iii) enter into certain sale-leaseback transactions. These covenants are subject to certain exceptions and qualifications

Table of Contents

Enable Oklahoma Senior Notes

As of December 31, 2014, our debt includes Enable Oklahoma's $250 million of 6.25% senior notes due March 2020, as a result of the 2013 acquisition of Enogex. These senior notes do not contain any financial covenants other than a limitation on liens. This limitation on liens is subject to important exceptions and qualifications.

Equity Issuances

On April 16, 2014, the Partnership completed the Offering of 25,000,000 common units, representing limited partner interests in the Partnership, at a price to the public of $20.00 per common unit. The Partnership received net proceeds of $464 million. The Partnership retained the net proceeds of the Offering for general partnership purposes, including the funding of expansion capital expenditures, and to pre-fund demand fees expected to be incurred over the next three years relating to certain expiring transportation and storage contracts.

Capital Requirements

The midstream business is capital intensive and can require significant investment to maintain and upgrade existing operations, connect new wells to the system, organically grow into new areas and comply with environmental and safety regulations. Going forward, our capital requirements will consist of the following:

- maintenance capital expenditures, which are cash expenditures (including expenditures for the construction or development of new capital assets or the replacement, improvement or expansion of existing capital assets) made to maintain, over the long-term, our operating capacity or operating income; and
- expansion capital expenditures, which are cash expenditures incurred for acquisitions or capital improvements that we expect will increase our operating income or operating capacity over the long term.

For the year ending December 31, 2015, we estimate that our maintenance and expansion capital expenditures could range from approximately $740 million to $960 million, not including opportunities currently under evaluation which could add up to an additional $300 million of expansion capital expenditures. Our future expansion capital expenditures may vary significantly from period to period based on the investment opportunities available to us. We expect to fund future capital expenditures from cash flow generated from our operations, borrowings under our Revolving Credit Facility, the issuance of commercial paper or new debt offerings or the issuance of additional partnership units.

Distributions

We intend to pay a minimum quarterly distribution of $0.2875 per unit per quarter. We do not have a legal obligation to pay this distribution.

In determining the amount of distributable cash flow, the Board of Directors determines the amount of cash reserves to set aside for our operations, including reserves for future working capital, maintenance capital expenditures, expansion capital expenditures, acquisitions and other matters, which will impact the amount of cash we are able to distribute to our unitholders. However, we expect that we will rely primarily upon external financing sources, including borrowings under our Revolving Credit Facility and issuances of debt and equity securities, as well as cash reserves, to fund our expansion capital expenditures including acquisitions. To the extent we are unable to finance growth externally and are unwilling to establish cash reserves to fund future expansions, our distributable cash flow will not significantly increase. In addition, because we distribute all of our available cash, we may not grow as quickly as businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any expansion capital expenditures including acquisitions, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement or in the terms of our Revolving Credit Facility on our ability to issue additional units, including units ranking senior to the common units.

We paid or have authorized payment of the following cash distributions under the Second Amended and Restated Agreement of Limited Partnership during the year ended December 31, 2014 (in millions, except for per unit amounts):

Quarter Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
June 30, 2014 [1]	August 4, 2014	August 14, 2014	$0.2464	$104
September 30, 2014	November 4, 2014	November 14, 2014	0.3025	128
December 31, 2014	February 4, 2015	February 13, 2015	0.30875	130

(1) The quarterly distribution for three months ended June 30, 2014 was prorated for the period beginning immediately after the closing of the Partnership's Offering, April 16, 2014 through June 30, 2014.

Contractual Obligations

In the ordinary course of business we enter into various contractual obligations for varying terms and amounts. The following table includes our contractual obligations and other commitments as of December 31, 2014 and our best estimate of the period in which the obligation will be settled:

	2015-2016	2017-2018	After 2018	Total
Maturities of short-term debt	$253	$—	$—	$—
Maturities of long-term debt[1][2]	—	—	1,900	1,900
Notes payable—affiliated companies[3]	—	363	—	363
Noncancellable operating leases	19	6	1	26
Other purchase obligations and commitments	6	—	—	6
Total contractual obligations	$278	$369	$1,901	$2,295

(1) Estimated contractual interest payments associated with long-term debt are $157 million, $157 million and $859 million in 2015 through 2016, 2017 through 2018 and after 2018, respectively. The Revolving Credit Facility estimated contractual interest payments are calculated utilizing the respective variable interest rates as of December 31, 2014.
(2) Excludes premium on Enable Oklahoma Senior Notes of $28 million.
(3) Estimated contractual interest payments associated with notes payable-affiliated companies are $16 million, $8 million and $-0- in 2015 through 2016, 2017 through 2018 and after 2018, respectively.

Customer Concentration

We rely on certain key natural gas producer customers for a significant portion of our natural gas and NGLs supply. For the year ended December 31, 2014, our top ten natural gas producer customers accounted for approximately 73% of our gathered volumes. These customers include affiliates of Encana, Apache, Vine, Chesapeake, XTO, Continental, Devon, Samson, BP and QEP.

We rely on certain key utilities for a significant portion of our transportation and storage demand. For the year ended December 31, 2014, our top transportation and storage customers by gross margin were affiliates of CenterPoint Energy, Laclede, AEP, XTO and OGE Energy.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Credit Risk

We are exposed to certain credit risks relating to our ongoing business operations. Credit risk includes the risk that counterparties that owe us money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected, and we could incur losses. We examine the creditworthiness of third party customers to whom we extend credit and manage our exposure to credit risk through credit analysis, credit approval, credit limits and monitoring procedures, and for certain transactions, we may request letters of credit, prepayments or guarantees.

Impact of Seasonality

While the results of our gathering and processing segment are not materially affected by seasonality, from time to time our operations can be impacted by inclement weather. Our transportation and storage segment experiences seasonal impacts associated with storage spreads, basis spreads on market-based pipelines, power plant demand and local distribution company customer demand.

Critical Accounting Policies and Estimates

Our financial statements and the related notes thereto contain information that is pertinent to Management’s Discussion and Analysis. In preparing our financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the Partnership’s financial statements. However, the Partnership believes it has taken reasonable, but conservative, positions where assumptions and estimates are used in order to minimize the negative financial impact to the Partnership that could result if actual results vary from the assumptions and estimates. In management’s opinion, the areas of the partnership where the most significant judgment is exercised for all partnership segments includes the determination of impairment estimates of long-lived assets (including intangible assets) and goodwill, valuation of revenues, natural gas purchases, valuation of assets, depreciable lives of property, plant and equipment and amortization methodologies related to intangible assets and commitments and contingencies. The selection, application and disclosure of the following critical accounting estimates have been discussed with the Partnership’s board of directors. The Partnership discusses its significant accounting policies, including those that do not require management to make difficult, subjective, or complex judgments or estimates, in Note 1 of the Notes to Combined and Consolidated Financial Statements.

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

The Partnership assesses its long-lived assets, including intangible assets with finite useful lives, for impairment when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset’s carrying amount. Estimates of future cash flows used to test the recoverability of long-lived assets and intangible assets shall include only the future cash flows (cash inflows less associated cash outflows) that are directly associated with and that are expected to arise as a direct result of the use and eventual disposition of the asset. The fair value of these assets is based on third-party evaluations, prices for similar assets, historical data and projected cash flows. An impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset. During the years ended December 31, 2014 and 2013, the Partnership recorded a $7 million and $12 million impairment, respectively, on the Service Star business line, a component of our gathering and processing segment. The Partnership recorded no other material impairments in the years ended December 31, 2014, 2013 or 2012.

The Partnership assesses its goodwill for impairment annually on October 1st, or more frequently if events or changes in circumstances indicate that the carrying value of goodwill may not be recoverable. Goodwill is assessed for impairment by comparing the fair value of the reporting unit with its book value, including goodwill. The Partnership tested its goodwill for impairment on May 1, 2013 upon formation and following formation tests annually on October 1. The Partnership utilizes the market or income approaches to estimate the fair value of the reporting unit, also giving consideration to the alternative cost approach. Under the market approach, historical and current year forecasted cash flows are multiplied by a market multiple to determine fair value. Under the income approach, anticipated cash flows over a period of years plus a terminal value are discounted to present value using appropriate discount rates. If the estimated fair value of the reporting unit is less than the carrying amount of the reporting unit, then a second step must be completed in order to determine the amount of the goodwill impairment that should be recorded. In the second step, the implied fair value of the reporting unit's goodwill is determined by allocating the reporting unit's fair value to all of its assets and liabilities other than goodwill (including any unrecognized intangible assets) in a manner similar to a purchase price allocation. The resulting implied fair value of the goodwill that results from the application of this second step is then compared to the carrying amount of the goodwill and an impairment charge is recorded for the difference. The Partnership performs its goodwill impairment testing one level below the Transportation and Storage and Gathering and Processing segment level at the operating segment level.

Table of Contents

Because quoted market prices for the Partnership’s reporting units are not available, management must apply judgment in determining the estimated fair value of reporting units for purposes of performing the goodwill impairment test, when necessary. Management considered observable transactions in the market, as well as trading multiples and cost of capital for peers, to determine appropriate multiples and discount rates to apply against historical and forecasted cash flows. A lower fair value estimate in the future for any of the Partnership’s reporting units could result in a goodwill impairment. Factors that could trigger a lower fair value estimate include sustained price declines, throughput declines, cost increases, regulatory or political environment changes, and other changes in market conditions such as decreased prices in market-based transactions for similar assets.

Subsequent to the completion of the annual test, the crude oil and natural gas industry was impacted by commodity price declines, which consequently resulted in decreased producer activity in certain regions in which the Partnership operates. Based on the decline in producer activity and the forecasted impact on future periods, the Partnership performed an interim assessment on the recoverability of goodwill for all of its reporting units as of December 31, 2014. Based on the Partnership’s most recent goodwill impairment test, management concluded that the fair value of each reporting unit exceeded the carrying value of the reporting unit and none of the reporting units were at risk of failing step one of the impairment test. The Partnership recorded no impairments of goodwill in the years ended December 31, 2014, 2013 or 2012.

	Interstate Transportation and Storage	Enable Oklahoma Gathering and Processing	Field Services
	(In millions, except percentages)		
Allocated Goodwill	$579	$439	$50
Excess fair value over carrying value	25.4 %	17.8 %	90.7 %

Revenues

Revenues for gathering, processing, transportation and storage services for the Partnership are recorded each month based on the current month’s estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current-month nominations and contracted prices. Revenues associated with the production of NGLs are estimated based on current-month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated revenues are reflected in Accounts Receivable or Accounts Receivable-affiliated companies, as appropriate, on the Consolidated Balance Sheets and in Revenues on the Combined and Consolidated Statements of Income.

The Partnership recognizes revenue from natural gas gathering, processing, transportation and storage and crude oil gathering services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold. The partnership records deferred revenue when it receives consideration from a third party before achieving certain criteria that must be met for revenue to be recognized in accordance with GAAP. The Partnership has $18 million and $9 million of deferred revenues on the Consolidated Balance Sheets as of December 31, 2014 and 2013, respectively.

Valuation of Assets

The application of business combination and impairment accounting requires the Partnership to use significant estimates and assumptions in determining the fair value of assets and liabilities. The acquisition method of accounting for business combinations requires the Partnership to estimate the fair value of assets acquired and liabilities assumed to allocate the proper amount of the purchase price consideration between goodwill and the assets that are depreciated and amortized. The Partnership records intangible assets separately from goodwill and amortizes intangible assets with finite lives over their estimated useful life as determined by management. The Partnership does not amortize goodwill but instead annually assesses goodwill for impairment.

In the year ended December 31, 2013, the Partnership completed acquisitions accounted for as business combinations as discussed in Note 3 of the Notes to Combined and Consolidated Financial Statements. As part of these acquisitions, the Partnership has engaged the services of third-party valuation experts to assist it in determining the fair value of the acquired assets and liabilities, including goodwill; however, the ultimate determination of those values is the responsibility of the Partnership's management. The Partnership bases its estimates on assumptions believed to be reasonable, but which are inherently uncertain. These valuations require the use of management's assumptions, which would not reflect unanticipated events and circumstances that may occur.

Table of Contents

Depreciable Lives of Property, Plant and Equipment and Amortization Methodologies Related to Intangible Assets

The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets at the time the assets are placed in service. As circumstances warrant, useful lives are adjusted when changes in planned use, changes in estimated production lives of affiliated natural gas basins or other factors indicate that a different life would be more appropriate. Such changes could materially impact future depreciation expense. Changes in useful lives that do not result in the impairment of an asset are recognized prospectively. The computation of amortization expense on intangible assets requires judgment regarding the amortization method used. Intangible assets are amortized on a straight-line basis over their useful lives using a method of amortization that reflects the pattern in which the economic benefits of the intangible asset are consumed.

Supplemental Disclosures

Certain information contained in this report relates to periods that began prior to the acquisition of Enogex by Enable Midstream Partners, LP. The Partnership believes that combined historical data with Enogex, along with certain pro forma adjustments, is relevant and meaningful, enhances the discussion of periods presented and is useful to the reader to better understand trends in the Partnership's operations. The pro forma adjustments, as discussed in the unaudited supplemental pro forma Combined Statement of Income below, only give effect to events that are (1) directly attributable to the formation of the Partnership; (2) factually supportable; and (3) expected to have a continuing effect on the consolidated results of the Partnership.

The following information is for informational purposes only and should not be considered indicative of future results. The following pro forma financial data was derived from the Partnership's combined financial information, Enogex consolidated financial information and certain adjustments described below. Further, management does not believe that the pro forma financial data is necessarily indicative of the financial data that would have been reported by the Partnership had the acquisition of Enogex closed prior to the historical period presented, future results of the Partnership, or other transactions that resulted in the formation of the Partnership.

Results of Operations—Pro Forma

The following table provides a summary of our results of operations on a historical basis for the year ended December 31, 2014 compared to our results of operations on a pro forma basis for the year ended December 31, 2013.

Historical Year Ended December 31, 2014	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Revenues	$2,424	$1,577	$(634)	$3,367
Cost of goods sold (excluding depreciation and amortization)	1,585	961	(632)	1,914
Gross margin on revenues	839	616	(2)	1,453
Operation and maintenance	297	232	(2)	527
Depreciation and amortization	160	116	—	276
Impairment	8	—	—	8
Taxes other than income tax	25	31	—	56
Operating income	$349	$237	$—	$586

Equity in earnings of equity method affiliates	$—	$20	$—	$20

Pro forma Year Ended December 31, 2013	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Revenues	$2,209	$1,447	$(536)	$3,120
Cost of goods sold (excluding depreciation and amortization)	1,447	885	(534)	1,798
Gross margin on revenues	762	562	(2)	1,322
Operation and maintenance	269	226	(2)	493
Depreciation and amortization	162	107	—	269
Impairment	12	—	—	12
Taxes other than income tax	24	38	—	62
Operating income	$295	$191	$—	$486
Equity in earnings of equity method affiliates	$—	$12	$—	$12

	Year Ended December 31,	
	Historical 2014	Pro Forma 2013
Operating Data:		
Gathered volumes—TBtu	1,221	1,298
Gathered volumes—TBtu/d	3.34	3.56
Natural gas processed volumes—TBtu	569	524
Natural gas processed volumes—TBtu/d	1.56	1.44
NGLs produced - MBbl/d(1)	66.74	59.45
NGLs sold - MBbl/d(1)(3)	68.67	59.82
Condensate sold - MBbl/d	4.38	2.96
Crude Oil - Gathered volumes - MBbl/d(2)	3.64	—
Transported volumes—TBtu	1,808	1,803
Transportation volumes—TBtu/d	4.95	4.94
Interstate firm contracted capacity—Bcf/d	7.73	8.01
Intrastate Transported volumes - TBtu/d	1.61	1.59

(1) Excludes condensate.
(2) Initial operation of our crude oil gathering system began on November 1, 2013.
(3) NGLs sold includes volumes of NGLs withdrawn from inventory or purchased for system balancing purposes.

Gathering and Processing

2014 compared to 2013. Our gathering and processing segment reported operating income of $349 million in the year ended December 31, 2014 compared to pro forma operating income of $295 million in the year ended December 31, 2013. Operating income increased $54 million primarily from an increase in gross margin of $77 million, a decrease in impairments of $4 million and a decrease in depreciation and amortization of $2 million, partially offset by an increase in operation and maintenance expenses of $28 million and an increase in taxes other than income tax of $1 million, during the year ended December 31, 2014.

Our gathering and processing segment gross margin increase