UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2016

OR

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

FOR THE TRANSITION PERIOD FROM __________________ TO __________________

Commission File Number 1-13265

CenterPoint Energy Resources Corp.

(Exact name of registrant as specified in its charter)

Delaware	**76-0511406**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
1111 Louisiana **Houston, Texas 77002**	**(713) 207-1111**
(Address and zip code of principal executive offices)	*(Registrant's telephone number, including area code)*

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

Title of each class	Name of each exchange on which registered
6.625% Senior Notes due 2037	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

CenterPoint Energy Resources Corp. meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No ☑

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o 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. Yes ☑ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein and will not be contained, to the best of the 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. ☑

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 definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o	Accelerated filer o	Non-accelerated filer ☑ (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).Yes o No ☑

The aggregate market value of the common equity held by non-affiliates as of June 30, 2016: None

TABLE OF CONTENTS

GLOSSARY

AEM	Atmos Energy Marketing, LLC, a wholly-owned subsidiary of Atmos Energy Holdings, Inc., a wholly-owned subsidiary of Atmos Energy Corporation
AFUDC	Allowance for funds used during construction
AMAs	Asset Management Agreements
APSC	Arkansas Public Service Commission
ArcLight	ArcLight Capital Partners, LLC
ARO	Asset retirement obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
Bcf	Billion cubic feet
Btu	British thermal units
CEA	Commodities Exchange Act
CEIP	CenterPoint Energy Intrastate Pipelines, LLC
CenterPoint Energy	CenterPoint Energy, Inc., and its subsidiaries
CERC Corp.	CenterPoint Energy Resources Corp.
CERC	CERC Corp., together with its subsidiaries
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CES	CenterPoint Energy Services, Inc.
CFTC	Commodity Futures Trading Commission
CIP	Conservation Improvement Program
Continuum	The retail energy services business of Continuum Retail Energy Services, LLC, including its wholly-owned subsidiary Lakeshore Energy Services, LLC and the natural gas wholesale assets of Continuum Energy Services, LLC
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
Dth	Dekatherms
EECR	Energy Efficiency Cost Recovery
EGT	Enable Gas Transmission, LLC
EIA	U.S. Energy Information Administration
Enable	Enable Midstream Partners, LP
EPA	Environmental Protection Agency
EPAct of 2005	Energy Policy Act of 2005
FASB	Financial Accounting Standards Board
Fitch	Fitch, Inc.
FRP	Formula Rate Plan
GenOn	GenOn Energy, Inc.
GHG	Greenhouse gases
GRIP	Gas Reliability Infrastructure Program
Houston Electric	CenterPoint Energy Houston Electric, LLC and its subsidiaries
HVAC	Heating, ventilation and air conditioning
IBEW	International Brotherhood of Electrical Workers
ICA	Interstate Commerce Act
IRS	Internal Revenue Service
LIBOR	London Interbank Offered Rate
LNG	Liquefied natural gas
LPSC	Louisiana Public Service Commission
MGPs	Manufactured gas plants

MLP	Master Limited Partnership
MMBtu	One million British thermal units
MMcf	Million cubic feet
Moody's	Moody's Investors Service, Inc.
MPSC	Mississippi Public Service Commission
MPUC	Minnesota Public Utilities Commission
MRT	Enable-Mississippi River Transmission, LLC
NAV	Net asset value
NESHAPS	National Emission Standards for Hazardous Air Pollutants
NGA	Natural Gas Act of 1938
NGD	Natural gas distribution business
NGLs	Natural gas liquids
NGPA	Natural Gas Policy Act of 1978
NGPSA	Natural Gas Pipeline Safety Act of 1968
NRG	NRG Energy, Inc.
NYSE	New York Stock Exchange
OCC	Oklahoma Corporation Commission
OGE	OGE Energy Corp.
PBRC	Performance Based Rate Change
PHMSA	Pipeline and Hazardous Materials Safety Administration
PRPs	Potentially responsible parties
Railroad Commission	Railroad Commission of Texas
RCRA	Resource Conservation and Recovery Act
REIT	Real Estate Investment Trust
Reliant Energy	Reliant Energy, Incorporated
ROE	Return on equity
RRA	Rate Regulation Adjustment
RRI	Reliant Resources, Inc.
RSP	Rate Stabilization Plan
SEC	Securities and Exchange Commission
SESH	Southeast Supply Header, LLC
Series A Preferred Units	Enable's 10% Series A Fixed-to-Floating Non-Cumulative Redeemable Perpetual Preferred Units
S&P	Standard & Poor's Ratings Services, a division of The McGraw-Hill Companies
Transition Agreements	Services Agreement, Employee Transition Agreement, Transitional Seconding Agreement and other agreements entered into in connection with the formation of Enable
VaR	Value at Risk
VIE	Variable interest entity
2002 Act	Pipeline Safety Improvement Act of 2002
2006 Act	Pipeline Inspection, Protection, Enforcement and Safety Act of 2006
2011 Act	Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011
2016 Act	Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016

We meet the conditions specified in General Instruction I(1)(a) and (b) of Form 10-K and are thereby permitted to use the reduced disclosure format for wholly-owned subsidiaries of reporting companies specified therein. Accordingly, we have omitted from this report the information called for by Item 10 (Directors, Executive Officers, and Corporate Governance), Item 11 (Executive Compensation), Item 12 (Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters) and Item 13 (Certain Relationships and Related Transactions, and Director Independence) of Form 10-K. In lieu of the information called for by Item 6 (Selected Financial Data) and Item 7 (Management's Discussion and Analysis of Financial Condition and Results of Operations) of Form 10-K, we have included, under Item 7, Management's Narrative Analysis of Results of Operations to explain the reasons for material changes in the amount of revenue and expense items between 2016, 2015 and 2014.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

From time to time we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, future events or performance and underlying assumptions and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Actual results may differ materially from those expressed or implied by these statements. You can generally identify our forward-looking statements by the words "anticipate," "believe," "continue," "could," "estimate," "expect," "forecast," "goal," "intend," "may," "objective," "plan," "potential," "predict," "projection," "should," "target," "will" or other similar words.

We have based our forward-looking statements on our management's beliefs and assumptions based on information reasonably available to our management at the time the statements are made. We caution you that assumptions, beliefs, expectations, intentions and projections about future events may and often do vary materially from actual results. Therefore, we cannot assure you that actual results will not differ materially from those expressed or implied by our forward-looking statements.

Some of the factors that could cause actual results to differ from those expressed or implied by our forward-looking statements are described under "Risk Factors" in Item 1A and "Management's Narrative Analysis of Results of Operations — Certain Factors Affecting Future Earnings" in Item 7 of this report, which discussions are incorporated herein by reference.

You should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement, and we undertake no obligation to update or revise any forward-looking statements.

PART I

Item 1. *Business*

OUR BUSINESS

Overview

We are an indirect, wholly-owned subsidiary of CenterPoint Energy, a public utility holding company. Our operating subsidiaries own and operate natural gas distribution facilities, supply natural gas to commercial and industrial customers and electric and natural gas utilities and own interests in Enable as described below. Our operating subsidiaries include:

- NGD, which owns and operates natural gas distribution systems in six states; and

- CES, which obtains and offers competitive variable and fixed-price physical natural gas supplies and services primarily to commercial and industrial customers and electric and natural gas utilities in 31 states.

As of December 31, 2016, we also owned approximately 54.1% of the limited partner interests in Enable, an unconsolidated partnership jointly controlled with OGE, which owns, operates and develops natural gas and crude oil infrastructure assets.

Our reportable business segments are Natural Gas Distribution, Energy Services, Midstream Investments and Other Operations. From time to time, we consider the acquisition or the disposition of assets or businesses.

Our principal executive offices are located at 1111 Louisiana, Houston, Texas 77002 (telephone number: 713-207-1111).

We make available free of charge on our parent company's Internet website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such reports with, or furnish them to, the SEC. Our parent company's website address is *www.centerpointenergy.com*. Except to the extent explicitly stated herein, documents and information on our parent company's website are not incorporated by reference herein.

Natural Gas Distribution

NGD engages in regulated intrastate natural gas sales to, and natural gas transportation and storage for, approximately 3.4 million residential, commercial, industrial and transportation customers in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas. The largest metropolitan areas served in each state by NGD are Houston, Texas; Minneapolis, Minnesota; Little Rock, Arkansas; Shreveport, Louisiana; Biloxi, Mississippi; and Lawton, Oklahoma. In 2016, approximately 37% of NGD's total throughput was to residential customers and approximately 63% was to commercial and industrial and transportation customers.

The table below reflects the number of NGD customers by state as of December 31, 2016:

	Residential	Commercial/ Industrial	Total Customers
Arkansas	379,117	48,161	427,278
Louisiana	230,475	16,842	247,317
Minnesota	778,731	69,856	848,587
Mississippi	112,992	12,548	125,540
Oklahoma	89,419	10,785	100,204
Texas	1,592,804	97,614	1,690,418
Total NGD	3,183,538	255,806	3,439,344

NGD also provides unregulated services in Minnesota consisting of residential appliance repair and maintenance services along with HVAC equipment sales.

Seasonality

The demand for intrastate natural gas sales to residential customers and natural gas sales and transportation for commercial and industrial customers is seasonal. In 2016, approximately 66% of NGD's total throughput occurred in the first and fourth quarters. These patterns reflect the higher demand for natural gas for heating purposes during the colder months.

Supply and Transportation. In 2016, NGD purchased virtually all of its natural gas supply pursuant to contracts with remaining terms varying from a few months to four years. Major suppliers in 2016 included the following:

Supplier	Percent of Supply Volumes
BP Energy Company/BP Canada Energy Marketing	17.7%
Macquarie Energy	16.3%
Tenaska Marketing Ventures	14.0%
Sequent Energy Management	8.0%
Kinder Morgan Tejas Pipeline/Kinder Morgan Texas Pipeline	7.1%
One Nation Energy Solutions	3.3%
Laclede Energy Resources	2.9%
Mieco	2.6%
CES	2.5%
Twin Eagle Resource Management	2.2%

Numerous other suppliers provided the remaining 23.4% of NGD's natural gas supply requirements. NGD transports its natural gas supplies through various intrastate and interstate pipelines under contracts with remaining terms, including extensions, varying from one to fifteen years. NGD anticipates that these gas supply and transportation contracts will be renewed or replaced prior to their expiration.

NGD actively engages in commodity price stabilization pursuant to annual gas supply plans presented to and/or filed with each of its state regulatory authorities. These price stabilization activities include use of storage gas and contractually establishing structured prices (e.g., fixed price, costless collars and caps) with our physical gas suppliers. Its gas supply plans generally call for 50–75% of winter supplies to be stabilized in some fashion.

The regulations of the states in which NGD operates allow it to pass through changes in the cost of natural gas, including savings and costs of financial derivatives associated with the index-priced physical supply, to its customers under purchased gas adjustment provisions in its tariffs. Depending upon the jurisdiction, the purchased gas adjustment factors are updated periodically, ranging from monthly to semi-annually. The changes in the cost of gas billed to customers are subject to review by the applicable regulatory bodies.

NGD uses various third-party storage services or owned natural gas storage facilities to meet peak-day requirements and to manage the daily changes in demand due to changes in weather. NGD may also supplement contracted supplies and storage from time to time with stored LNG and propane-air plant production.

NGD owns and operates an underground natural gas storage facility with a capacity of 7.0 Bcf. It has a working capacity of 2.0 Bcf available for use during the heating season and a maximum daily withdrawal rate of 50 MMcf. It also owns eight propane-air plants with a total production rate of 180,000 Dth per day and on-site storage facilities for 12 million gallons of propane (1.0 Bcf natural gas equivalent). It owns a LNG plant facility with a 12 million-gallon LNG storage tank (1.0 Bcf natural gas equivalent) and a production rate of 72,000 Dth per day.

On an ongoing basis, NGD enters into contracts to provide sufficient supplies and pipeline capacity to meet its customer requirements. However, it is possible for limited service disruptions to occur from time to time due to weather conditions, transportation constraints and other events. As a result of these factors, supplies of natural gas may become unavailable from time to time, or prices may increase rapidly in response to temporary supply constraints or other factors.

NGD has had AMAs associated with its utility distribution service in Arkansas, Louisiana, Mississippi, Oklahoma and Texas. Generally, AMAs are contracts between NGD and an asset manager that are intended to transfer the working capital obligation and maximize the utilization of the assets. In these agreements, NGD agrees to release transportation and storage capacity to other parties to manage natural gas storage, supply and delivery arrangements for NGD and to use the released capacity for other purposes when it is not needed for NGD. NGD is compensated by the asset manager through payments made over the life of the agreements based in part on the results of the asset optimization. NGD has an obligation to purchase its winter storage requirements that have been released to the asset manager under these AMAs. NGD has received approval from the state regulatory commissions in Arkansas, Louisiana, Mississippi and Oklahoma to retain a share of the AMA proceeds. NGD currently has AMAs in Arkansas, north Louisiana and Oklahoma that extend through 2020.

Assets

As of December 31, 2016, NGD owned approximately 74,000 linear miles of natural gas distribution mains, varying in size from one-half inch to 24 inches in diameter. Generally, in each of the cities, towns and rural areas served by NGD, it owns the underground gas mains and service lines, metering and regulating equipment located on customers' premises and the district regulating equipment necessary for pressure maintenance. With a few exceptions, the measuring stations at which NGD receives gas are owned, operated and maintained by others, and its distribution facilities begin at the outlet of the measuring equipment. These facilities, including odorizing equipment, are usually located on land owned by suppliers.

Competition

NGD competes primarily with alternate energy sources such as electricity and other fuel sources. In some areas, intrastate pipelines, other gas distributors and marketers also compete directly for gas sales to end users. In addition, as a result of federal regulations affecting interstate pipelines, natural gas marketers operating on these pipelines may be able to bypass NGD's facilities and market and sell and/or transport natural gas directly to commercial and industrial customers.

Energy Services

We offer competitive variable and fixed-priced physical natural gas supplies primarily to commercial and industrial customers and electric and natural gas utilities through CES and its subsidiary, CEIP.

In 2016, CES marketed approximately 777 Bcf of natural gas, related energy services and transportation to approximately 31,000 customers (including approximately 8 Bcf to affiliates) in 31 states. These totals include approximately 13,000 customers and 175 Bcf of natural gas related to the acquisition of Continuum, which closed in April 2016, and was fully integrated into CES by the end of 2016. CES customers vary in size from small commercial customers to large utility companies. Not included in the 2016 customer count are approximately 60,000 natural gas customers that are served under residential and small commercial choice programs invoiced by their host utility. These customers are not included in customer count so as not to distort the significant margin impact from the remaining customer base.

In January 2017, CES completed the acquisition of AEM. For information related to this acquisition, see Note 17 to our consolidated financial statements.

CES offers a variety of natural gas management services to gas utilities, large industrial customers, electric generators, smaller commercial and industrial customers, municipalities, educational institutions and hospitals. These services include load forecasting, supply acquisition, daily swing volume management, invoice consolidation, storage asset management, firm and interruptible transportation administration and forward price management. CES also offers a portfolio of physical delivery services designed to meet customers' supply and price risk management needs. These customers are served directly, through interconnects with various interstate and intrastate pipeline companies, and portably, through our mobile energy solutions business.

In addition to offering natural gas management services, CES procures and optimizes transportation and storage assets. CES maintains a portfolio of natural gas supply contracts and firm transportation and storage agreements to meet the natural gas requirements of its customers. CES aggregates supply from various producing regions and offers contracts to buy natural gas with terms ranging from one month to over five years. In addition, CES actively participates in the spot natural gas markets in an effort to balance daily and monthly purchases and sales obligations. Natural gas supply and transportation capabilities are leveraged through contracts for ancillary services including physical storage and other balancing arrangements.

As described above, CES offers its customers a variety of load following services. In providing these services, CES uses its customers' purchase commitments to forecast and arrange its own supply purchases, storage and transportation services to serve customers' natural gas requirements. As a result of the variance between this forecast activity and the actual monthly activity, CES will either have too much supply or too little supply relative to its customers' purchase commitments. These supply imbalances arise each month as customers' natural gas requirements are scheduled and corresponding natural gas supplies are nominated by CES for delivery to those customers. CES' processes and risk control environment are designed to measure and value imbalances on a real-time basis to ensure that CES' exposure to commodity price risk is kept to a minimum. The value assigned to these imbalances is calculated daily and is known as the aggregate VaR.

Our risk control policy, which is overseen by CenterPoint Energy's Risk Oversight Committee, defines authorized and prohibited trading instruments and trading limits. CES is a physical marketer of natural gas and uses a variety of tools, including pipeline and storage capacity, financial instruments and physical commodity purchase contracts, to support its sales. CES optimizes its use of these various tools to minimize its supply costs and does not engage in speculative commodity trading. The VaR limit within which CES currently operates, a $4 million maximum set by CenterPoint Energy's board of directors, is consistent with CES' operational objective of matching its aggregate sales obligations (including the swing associated with load following services) with its supply portfolio in a manner that minimizes its total cost of supply. In 2016, CES' VaR averaged $0.2 million with a high of $1.0 million.

Assets

CEIP owns and operates over 200 miles of intrastate pipeline in Louisiana and Texas. In addition, CES leases transportation capacity on various interstate and intrastate pipelines and storage to service its shippers and end users.

Competition

CES competes with regional and national wholesale and retail gas marketers, including the marketing divisions of natural gas producers and utilities. In addition, CES competes with intrastate pipelines for customers and services in its market areas.

Midstream Investments

Our Midstream Investments business segment consists of our equity method investment in Enable. Enable is a publicly traded MLP, jointly controlled by us and OGE.

Enable. Enable was formed to own, operate and develop strategically located natural gas and crude oil infrastructure assets. Enable serves 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. Enable's assets and operations are organized into two reportable segments: (i) gathering and processing, which primarily provides natural gas gathering, processing and fractionation services and crude oil gathering for its producer customers, and (ii) transportation and storage, which provides interstate and intrastate natural gas pipeline transportation and storage services primarily to natural gas producers, utilities and industrial customers.

Enable's natural gas gathering and processing assets are located in Oklahoma,Texas, Arkansas, Louisiana and Mississippi and serve natural gas production in the Anadarko, Arkoma and Ark-La-Tex basins. Enable also owns a crude oil gathering business located in North Dakota that commenced initial operations in November 2013 to serve shale development in the Bakken Shale formation of the Williston Basin. Enable's natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

Enable's Gathering and Processing segment. Enable provides gathering, compression, treating, dehydration, processing and NGLs fractionation for producers who are active in the areas in which Enable operates. Enable's super-header system is intended to optimize the economics of its natural gas processing and to improve system utilization and reliability.

Enable's 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, Enable competes against other natural gas processors extracting and selling NGLs. Enable's primary competitors are master limited partnerships who are active in the regions where it operates.

Enable's Transportation and Storage segment. Enable provides fee-based interstate and intrastate transportation and storage services across nine states. Enable's transportation and storage assets were designed and built to serve large natural gas and electric utility companies in its areas of operation.

Enable's interstate pipelines compete with other interstate and intrastate pipelines. Enable's 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 among pipelines are rates, terms of service, and flexibility and reliability of service.

For information related to our equity method investment in Enable, see Notes 2(b), 11 and 17 to our consolidated financial statements.

Other Operations

Our Other Operations business segment includes unallocated corporate costs and inter-segment eliminations.

Financial Information About Segments

For financial information about our segments, see Note 16 to our consolidated financial statements, which note is incorporated herein by reference.

REGULATION

We are subject to regulation by various federal, state and local governmental agencies, including the regulations described below.

Federal Energy Regulatory Commission

The FERC has jurisdiction under the NGA and the NGPA, as amended, to regulate the transportation of natural gas in interstate commerce and natural gas sales for resale in interstate commerce that are not first sales. The FERC regulates, among other things, the construction of pipeline and related facilities used in the transportation and storage of natural gas in interstate commerce, including the extension, expansion or abandonment of these facilities. The FERC has authority to prohibit market manipulation in connection with FERC-regulated transactions and to impose significant civil and criminal penalties for statutory violations and violations of the FERC's rules or orders. Our Energy Services business segment markets natural gas in interstate commerce pursuant to blanket authority granted by the FERC.

As a public utility holding company, under the Public Utility Holding Company Act of 2005, CenterPoint Energy is subject to reporting and accounting requirements and is required to maintain certain books and records and make them available for review by the FERC and state regulatory authorities in certain circumstances.

State and Local Regulation

In almost all communities in which NGD provides natural gas distribution services, it operates under franchises, certificates or licenses obtained from state and local authorities. The original terms of the franchises, with various expiration dates, typically range from 10 to 30 years, although franchises in Arkansas are perpetual. NGD expects to be able to renew expiring franchises. In most cases, franchises to provide natural gas utility services are not exclusive.

Substantially all of NGD is subject to cost-of-service rate regulation by the relevant state public utility commissions and, in Texas, by the Railroad Commission and those municipalities served by NGD that have retained original jurisdiction. In certain of its jurisdictions, NGD has in effect annual rate adjustment mechanisms that provide for changes in rates dependent upon certain changes in invested capital, earned returns on equity or actual margins realized.

For a discussion of certain of NGD's ongoing regulatory proceedings, see "Management's Narrative Analysis of Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report, which discussion is incorporated herein by reference.

Department of Transportation

In December 2006, Congress enacted the 2006 Act, which reauthorized the programs adopted under the 2002 Act. These programs included several requirements related to ensuring pipeline safety, and a requirement to assess the integrity of pipeline transmission facilities in areas of high population concentration.

Pursuant to the 2006 Act, PHMSA at the DOT issued regulations, effective February 12, 2010, requiring operators of gas distribution pipelines to develop and implement integrity management programs similar to those required for gas transmission pipelines, but tailored to reflect the differences in distribution pipelines. Operators of natural gas distribution systems were required to write and implement their integrity management programs by August 2, 2011. Our natural gas distribution systems met this deadline.

Pursuant to the 2002 Act and the 2006 Act, PHMSA has adopted a number of rules concerning, among other things, distinguishing between gathering lines and transmission facilities, requiring certain design and construction features in new and replaced lines to reduce corrosion and requiring pipeline operators to amend existing written operations and maintenance procedures and operator qualification programs. PHMSA also updated its reporting requirements for natural gas pipelines effective January 1, 2011.

In December 2011, Congress passed the 2011 Act. This act increases the maximum civil penalties for pipeline safety administrative enforcement actions; requires the DOT to study and report on the expansion of integrity management requirements and the sufficiency of existing gathering line regulations to ensure safety; requires pipeline operators to verify their records on maximum allowable operating pressure; and imposes new emergency response and incident notification requirements. In 2016, the 2016 Act reauthorized PHMSA's pipeline safety programs through 2019 and provided limited new authority, including the ability to issue emergency orders, to set inspection requirements for certain underwater pipelines and to promulgate minimum safety standards for natural gas storage facilities, as well as to provide increased transparency into the status of as-yet-incomplete PHMSA actions required by the 2011 Act.

We anticipate that compliance with PHMSA's regulations, performance of the remediation activities by CERC's natural gas distribution companies and intrastate pipelines and verification of records on maximum allowable operating pressure will continue to require increases in both capital expenditures and operating costs. The level of expenditures will depend upon several factors, including age, location and operating pressures of the facilities. In particular, the cost of compliance with the DOT's integrity management rules will depend on integrity testing and the repairs found to be necessary by such testing. Changes to the amount of pipe subject to integrity management, whether by expansion of the definition of the type of areas subject to integrity management procedures or of the applicability of such procedures outside of those defined areas, may also affect the costs we incur. Implementation of the 2011 and 2016 Acts by PHMSA may result in other regulations or the reinterpretation of existing regulations that could impact our compliance costs. In addition, we may be subject to the DOT's enforcement actions and penalties if we fail to comply with pipeline regulations.

Midstream Investments – Rate and Other Regulation

Federal, state, and local regulation may affect certain aspects of Enable's business.

Interstate Natural Gas Pipeline Regulation

Enable's interstate pipeline systems—EGT, MRT and SESH—are subject to regulation by the FERC under the NGA and are considered natural gas companies. Under the NGA, the rates for service on Enable's interstate facilities must be just and reasonable and not unduly discriminatory. Tariff changes for these facilities can only be implemented upon approval by the FERC. Enable's 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.

Market Behavior Rules; Posting and Reporting Requirements

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 as prescribed in FERC rules, which were subsequently issued in FERC Order No. 670. The EPAct of 2005 also amends the NGA and the NGPA to give the FERC authority to impose civil penalties for violations of these statutes and FERC's regulations, rules, and orders, of up to $1 million per day per violation, subject to periodic adjustment to account for inflation. Should Enable fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, it could be subject to substantial penalties and fines. In addition, the CFTC is directed under the 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. These maximum penalty levels are also subject to periodic adjustment to account for inflation.

Intrastate Natural Gas Pipeline and Storage Regulation

Intrastate natural gas transportation is largely regulated by the state in which the transportation takes place. However, 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. Rates for service pursuant to Section 311 of the NGPA are generally subject to review and approval by the FERC at least once every five years. Failure to observe the service limitations applicable to transportation services provided under Section 311, failure to comply with the rates approved by the 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 the

FERC and/or the imposition of administrative, civil and criminal penalties, as described under "—Interstate Natural Gas Pipeline Regulation" above.

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 the facilities Enable considers to be gathering facilities, Enable believes that its 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, 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 Enable's gathering facilities is subject to change based on future determinations.

States may regulate gathering pipelines. State regulation generally includes various safety, environmental and, in some circumstances, anti-discrimination requirements, and in some instances complaint-based rate regulation. Enable's gathering operations may be subject to ratable take and common purchaser statutes in the states in which they operate.

Enable's 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. Enable's 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. We cannot predict what effect, if any, such changes might have on Enable's operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Crude Oil Gathering Regulation

Enable provides interstate transportation on its crude oil gathering system in North Dakota pursuant to a public tariff in accordance with FERC regulatory requirements. Crude oil gathering pipelines that provide interstate transportation service may be regulated as a common carrier by the 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 non-discriminatory or not conferring any undue preference upon any shipper. FERC regulations also require interstate common carrier petroleum pipelines to file with the FERC and publicly post tariffs stating their interstate transportation rates and terms and conditions of service.

Safety and Health Regulation

Certain of Enable's 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 Enable's interstate natural gas pipelines, are subject to PHMSA's regulations, but natural gas gathering pipelines are subject 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.

Pursuant to various federal statutes, including the NGPSA, the DOT, through PHMSA, regulates pipeline safety and integrity. NGL and crude oil pipelines are subject to regulation by PHMSA under the Hazardous Liquid Pipeline Safety Act 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. Should Enable fail to comply with DOT or comparable state regulations, it could be subject to penalties and fines. If future DOT pipeline regulations were to require that Enable expand its integrity management program to currently unregulated pipelines, costs associated with compliance may have a material effect on its operations.

ENVIRONMENTAL MATTERS

Our operations and the operations of Enable are subject to stringent and complex laws and regulations pertaining to the environment. As an owner or operator of natural gas pipelines, distribution systems and storage, and the facilities that support these systems, we must comply with these laws and regulations at the federal, state and local levels. 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;

- limiting or prohibiting construction activities in sensitive areas such as wetlands, coastal regions or areas inhabited by endangered species;
- requiring remedial action to mitigate environmental conditions caused by our operations or attributable to former operations;
- enjoining the operations of facilities with permits issued pursuant to such environmental laws and regulations; and
- impacting the demand for our services by directly or indirectly affecting the use or price of natural gas.

To comply with these requirements, we may need to spend substantial amounts and devote other resources from time to time to, among other activities:

- construct or acquire new facilities and equipment;
- acquire permits for facility operations;
- modify, upgrade or replace existing and proposed equipment; and
- clean or decommission waste management areas, fuel storage facilities and other locations.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial actions and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been stored, disposed or released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

The recent trend in environmental regulation has been to place more restrictions and limitations on activities that may impact the environment. For example, the EPA has established air emission control requirements for natural gas and NGL production, processing and transportation activities, which may affect Enable's midstream operations. These include New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, and the NESHAPS to address hazardous air pollutants frequently associated with natural gas production and processing activities. There can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to maintain compliance with changing environmental laws and regulations and to ensure the costs of such compliance are reasonable.

Based on current regulatory requirements and interpretations, we do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position, results of operations or cash flows. In addition, we believe that our current environmental remediation activities will not materially interrupt or diminish our operational ability. We cannot assure you that future events, such as changes in existing laws, the promulgation of new laws, or the development or discovery of new facts or conditions will not cause us to incur significant costs. The following is a discussion of material current environmental and safety laws and regulations that relate to our operations. We believe that we are in substantial compliance with these environmental laws and regulations.

Global Climate Change

There is increasing attention being paid in the United States and worldwide to the issue of climate change. As a result, from time to time, regulatory agencies have considered the modification of existing laws or regulations or the adoption of new laws or regulations addressing the emissions of GHG on the state, federal, or international level. Some of the proposals would require industrial sources to meet stringent new standards that would require substantial reductions in GHG emissions. Our revenues, operating costs and capital requirements could be adversely affected as a result of any regulatory action that would require installation of new control technologies or a modification of our operations or would have the effect of reducing the consumption of natural gas. Likewise, incentives to conserve energy or use energy sources other than natural gas could result in a decrease in demand for our services. Conversely, regulatory actions that effectively promote the consumption of natural gas because of its lower emissions characteristics would be expected to beneficially affect us and our natural gas-related businesses. At this point in time, however, it would be speculative to try to quantify the magnitude of the impacts from possible new regulatory actions related to GHG emissions, either positive or negative, on our businesses.

To the extent climate changes occur, our businesses may be adversely impacted, though we believe any such impacts are likely to occur very gradually and hence would be difficult to quantify. To the extent global climate change results in warmer temperatures in our service territories, financial results from our natural gas distribution business could be adversely affected through lower gas sales. Another possible result of climate change is more frequent and more severe weather events, such as hurricanes or tornadoes. Since many of our facilities are located along or near the Gulf Coast, increased or more severe hurricanes or tornadoes could increase our costs to repair damaged facilities and restore service to our customers. When we cannot deliver natural gas to customers, or our customers cannot receive our services, our financial results can be impacted by lost revenues, and we generally must seek approval from regulators to recover restoration costs. To the extent we are unable to recover those costs, or if higher rates resulting from our recovery of such costs result in reduced demand for our services, our future financial results may be adversely impacted.

Air Emissions

Our operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require 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. We may be required to obtain and strictly comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions. Failure to comply with these requirements could result in monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

The EPA has established new air emission control requirements for natural gas and NGLs production, processing and transportation activities. Under the NESHAPS, the EPA established maximum achievable control technology for stationary internal combustion engines (sometimes referred to as the RICE MACT rule). Compressors and back up electrical generators used by our Natural Gas Distribution business segment are substantially compliant with these laws and regulations.

Water Discharges

Our operations are subject to the Federal Water Pollution Control Act of 1972, as amended, also known as the 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 waters of the United States. The unpermitted discharge of pollutants, including discharges resulting from a spill or leak incident, is prohibited. The 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. Any unpermitted release of petroleum or other pollutants from our pipelines or facilities could result in fines or penalties as well as significant remedial obligations.

Hazardous Waste

Our operations generate wastes, including some hazardous wastes, that are subject to the federal RCRA, and comparable state laws, which impose detailed requirements for the handling, storage, treatment, transport and disposal of hazardous and solid waste. RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous waste waters produced and other wastes associated with the exploration, development or production of crude oil and natural gas. However, these oil and gas exploration and production wastes are still regulated under state law and the less stringent non-hazardous waste requirements of RCRA. Moreover, ordinary industrial wastes such as paint wastes, waste solvents, laboratory wastes and waste compressor oils may be regulated as hazardous waste. The transportation of natural gas in pipelines may also generate some hazardous wastes that would be subject to RCRA or comparable state law requirements.

Liability for Remediation

CERCLA, also known as “Superfund,” and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Such classes of persons include the current and past owners or operators of sites where a hazardous substance was released and companies that disposed or arranged for the disposal of hazardous substances at offsite locations such as landfills. Although petroleum, as well as natural gas, is excluded from CERCLA’s definition of a “hazardous substance,” in the course of our ordinary operations we generate wastes that may fall within the definition of a “hazardous substance.” CERCLA authorizes the EPA and, in some cases, third parties to take action in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. Under CERCLA, we could be subject to joint and several liability for the costs of cleaning up and restoring sites where hazardous substances have been released, for damages to natural resources, and for the costs of certain health studies.

Liability for Preexisting Conditions

For information about preexisting environmental matters, please see Note 14(d).

EMPLOYEES

As of December 31, 2016, we had 3,467 full-time employees. The following table sets forth the number of our employees by business segment as of December 31, 2016:

Business Segment	Number	Number Represented by Unions or Other Collective Bargaining Groups
Natural Gas Distribution	3,246	1,179
Energy Services	221	—
Total	3,467	1,179

As of December 31, 2016, approximately 34% of our employees were covered by collective bargaining agreements. The collective bargaining agreement with the Professional Employees International Union Local 12, which covers approximately 3% of our employees, expired in May of 2016. We successfully negotiated the follow-on agreement in 2016. The new collective bargaining agreement expires in May of 2021.

The collective bargaining agreements with Gas Workers Union, Local 340 and the IBEW, Local 949, covering approximately 19% of our employees, will expire in April and December of 2020, respectively. These two agreements were last negotiated in 2015.

The two collective bargaining agreements with the United Steelworkers Union, Locals 13-227 and 13-1, which cover approximately 12% of our employees, are scheduled to expire in June and July of 2017, respectively. We believe we have good relationships with these bargaining units and expect to negotiate new agreements in 2017.

Item 1A. *Risk Factors*

The following, along with any additional legal proceedings identified or incorporated by reference in Item 3 of this report, summarizes the principal risk factors associated with our businesses and our interests in Enable:

Risk Factors Associated with Our Consolidated Financial Condition

We are an indirect, wholly-owned subsidiary of CenterPoint Energy. CenterPoint Energy can exercise substantial control over our dividend policy and business and operations and could do so in a manner that is adverse to our interests.

We are managed by officers and employees of CenterPoint Energy. Our management will make determinations with respect to the following:

- our payment of dividends;
- our financings and our capital raising activities;
- mergers or other business combinations; and
- our acquisition or disposition of assets.

Other than the financial covenants contained in our credit facility (described under "Liquidity and Capital Resources" in Item 7 of this report), which could have the practical effect of limiting the payment of dividends under certain circumstances, there are no contractual restrictions on our ability to pay dividends to CenterPoint Energy. Our management could decide to increase our dividends to CenterPoint Energy to support its cash needs. This could adversely affect our liquidity. However, under our credit facility, our ability to pay dividends is restricted by a covenant that debt as a percentage of total capitalization may not exceed 65%.

If we are unable to arrange future financings on acceptable terms, our ability to refinance existing indebtedness could be limited.

As of December 31, 2016, we had $2.4 billion of outstanding indebtedness on a consolidated basis. As of December 31, 2016, approximately $550 million principal amount of this debt is required to be paid through 2019. Our future financing activities may be significantly affected by, among other things:

- general economic and capital market conditions;
- credit availability from financial institutions and other lenders;
- volatility or fluctuations in distributions from Enable's units or volatility in Enable's unit price;
- investor confidence in us and CenterPoint Energy and the markets in which we operate;
- maintenance of acceptable credit ratings by us and CenterPoint Energy;
- market expectations regarding our and CenterPoint Energy's future earnings and cash flows;
- our and CenterPoint Energy's ability to access capital markets on reasonable terms;
- our exposure to GenOn (formerly known as RRI Energy, Inc., Reliant Energy and RRI), a wholly-owned subsidiary of NRG, in connection with certain indemnification obligations;
- incremental collateral that may be required due to regulation of derivatives; and
- provisions of relevant tax and securities laws.

Our current credit ratings are discussed in "Management's Narrative Analysis of Results of Operations — Liquidity and Capital Resources — Impact on Liquidity of a Downgrade in Credit Ratings" in Item 7 of this report. These credit ratings may not remain in effect for any given period of time and one or more of these ratings may be lowered or withdrawn entirely by a rating agency. We note that these credit ratings are not recommendations to buy, sell or hold our securities. Each rating should be evaluated independently of any other rating. Any future reduction or withdrawal of one or more of our credit ratings could have a material adverse impact on our ability to access capital on acceptable terms.

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

Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. Accounting principles generally accepted in the United States of America require us to test goodwill 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 investments we account for under the equity method, the impairment test considers whether the fair value of such equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. For example, during the year ended December 31, 2015, we determined that an other than temporary decrease in the value of our equity investment in Enable had occurred. This determination was based on the sustained low Enable common unit price and further declines in such price during the year, as well as the market outlook for continued depressed crude oil and natural gas prices impacting the midstream oil and gas industry. We wrote down the value of our investment in Enable to its estimated fair value which resulted in impairment charges of $1,225 million for the year ended December 31, 2015. Additionally, we recorded our share, $621 million, of impairment charges Enable recorded for goodwill and long-lived assets, for a total impairment charge of $1,846 million.

If Enable's unit price, distributions or earnings were to decline to levels below those used in our impairment tests in 2015, and that decline is deemed to be other than temporary, we could determine that we are unable to recover the carrying value of our equity investment in Enable. Considerable judgment is used in determining if an impairment loss is other than temporary and the amount of any impairment. A sustained low Enable common unit price could result in our recording further impairment charges in the future. 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.

The creditworthiness and liquidity of our parent company and our affiliates could affect our creditworthiness and liquidity.

Our credit ratings and liquidity may be impacted by the creditworthiness and liquidity of our parent company and our affiliates. As of December 31, 2016, CenterPoint Energy and its subsidiaries other than us had approximately $300 million principal amount of debt required to be paid through 2019. This amount excludes principal repayments of approximately $1.3 billion on transition and system restoration bonds, for which dedicated revenue streams exist, and indexed debt securities obligations. If CenterPoint Energy were to experience a deterioration in its creditworthiness or liquidity, our creditworthiness and liquidity could be adversely affected. In addition, CenterPoint Energy or its other subsidiaries or affiliates may from time to time acquire or dispose of assets or businesses or enter into joint ventures or other transactions that could adversely impact the credit capacity, credit ratings or liquidity of CenterPoint Energy or its other subsidiaries or affiliates, which, as a result, could adversely impact our credit ratings and liquidity. Also, from time to time we and other affiliates invest or borrow funds in the money pool maintained by CenterPoint Energy. If CenterPoint Energy or the affiliates that borrow any funds that we might invest from time to time in the money pool were to experience a deterioration in their creditworthiness or liquidity, our creditworthiness, liquidity and the repayment of notes receivable from CenterPoint Energy and our affiliates participating in the money pool could be adversely impacted.

The use of derivative contracts in the normal course of business by us, our subsidiaries or Enable could result in financial losses that could negatively impact our results of operations and those of our subsidiaries or Enable.

We and our subsidiaries use derivative instruments, such as swaps, options, futures and forwards, to manage our commodity, weather and financial market risks. Enable may also use such instruments from time to time to manage its commodity and financial market risk. We, our subsidiaries or Enable could recognize financial losses as a result of volatility in the market values or ineffectiveness 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.

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

We derive a substantial portion of our operating income from, and hold a substantial portion of our assets through, our subsidiaries. As a result, we depend on distributions from our subsidiaries, including Enable, 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.

For a discussion of risks that may impact the amount of cash distributions we receive with respect to our interests in Enable, please read "—Additional Risk Factors Affecting our Interests in Enable Midstream Partners, LP — Our cash flows will be adversely impacted if we receive less cash distributions from Enable than we currently expect."

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.

Risk Factors Affecting Our Natural Gas Distribution and Energy Services Businesses

Rate regulation of our business may delay or deny our ability to earn a reasonable return and fully recover our costs.

Our rates for NGD are regulated by certain municipalities (in Texas only) and state commissions in the context of comprehensive base rate proceedings, i.e., general rate cases, based on an analysis of NGD's invested capital, expenses and other factors in a test year (often either fully or partially historic), subject to periodic review and adjustment. A general rate case is also a very complex and resource intensive proceeding with a relatively long timeline for completion. Thus, the rates that CERC is allowed to charge may not match its costs at any given time, resulting in what is referred to as "regulatory lag."

Though several interim rate adjustment mechanisms have been approved by jurisdictional regulatory authorities and implemented by NGD to reduce the effects of regulatory lag, such adjustment mechanisms are subject to the applicable regulatory body's approval and are subject to certain limitations that may reduce NGD's ability to adjust its rates.

Arkansas enacted legislation in 2015 allowing public utilities to elect to have their rates regulated pursuant to a FRP, but such legislation provides for a utility's base rates to be adjusted once a year. In each of Louisiana, Mississippi and Oklahoma, NGD makes annual filings utilizing various formula rate mechanisms that adjust rates based on a comparison of authorized return to actual return to achieve the allowed return rates in those jurisdictions. Additionally, in Minnesota, the MPUC implemented a full revenue decoupling pilot program in 2015, which separates approved revenues from the amount of natural gas used by its customers. The effectiveness of these filings and programs depends on the approval of the applicable state regulatory body.

In Texas, NGD's Houston, South Texas, Beaumont/East Texas and Texas Coast divisions each submit annual GRIP filings to recover the incremental capital investments made in the preceding year. NGD must file a general rate case no later than five years after the initial GRIP implementation date.

NGD can make no assurances that such filings will result in favorable adjustments to its rates. Notwithstanding the application of the rate mechanisms discussed above, the regulatory process in which rates are determined may not always result in rates that will produce full recovery of NGD's costs and enable NGD to earn a reasonable return on its invested capital. Additionally, inherent in the regulatory process is some level of risk that jurisdictional regulatory authorities may initiate investigations of the prudence of operating expenses incurred or capital investments made by NGD and deny the full recovery of NGD's cost of service or the full recovery of incurred natural gas costs in rates. To the extent the regulatory process does not allow NGD to make a full and timely recovery of appropriate costs, our results of operations, financial condition and cash flows could be adversely affected.

Our natural gas distribution and energy services businesses, including transportation and storage, are subject to fluctuations in notional natural gas prices as well as geographic and seasonal natural gas price differentials, which could affect the ability of our suppliers and customers to meet their obligations or otherwise adversely affect our liquidity and results of operations and financial condition.

We are subject to risk associated with changes in the notional price of natural gas as well as geographic and seasonal natural gas price differentials. Increases in natural gas prices might affect our ability to collect balances due from our customers and, for NGD, could create the potential for uncollectible accounts expense to exceed the recoverable levels built into our tariff rates. In addition, a sustained period of high natural gas prices could (i) decrease demand for natural gas in the areas in which we operate, thereby resulting in decreased sales and revenues and (ii) increase the risk that our suppliers or customers fail or are unable to meet their obligations. An increase in natural gas prices would also increase our working capital requirements by increasing the investment that must be made in order to maintain natural gas inventory levels. Additionally, a decrease in natural gas prices could increase the amount of collateral that we must provide under our hedging arrangements.

A decline in our credit rating could result in our having to provide collateral under our shipping or hedging arrangements or to purchase natural gas.

If our credit rating were to decline, we might be required to post cash collateral under our shipping or hedging arrangements or to purchase natural gas. 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, financial condition and cash flows could be adversely affected.

Our revenues and results of operations are seasonal.

A substantial portion of our revenues is derived from natural gas sales. Thus, our revenues and results of operations are subject to seasonality, weather conditions and other changes in natural gas usage, with revenues being higher during the winter months. Unusually mild weather in the winter months could diminish our results of operations and harm our financial condition. Conversely, extreme cold weather conditions could increase our results of operations in a manner that would not likely be annually recurring.

The states in which we provide regulated local natural gas distribution may, either through legislation or rules, adopt restrictions regarding organization, financing and affiliate transactions that could have significant adverse impacts on our ability to operate.

From time to time, proposals have been put forth in some of the states in which we do business to give state regulatory authorities increased jurisdiction and scrutiny over organization, capital structure, intracompany relationships and lines of business that could be pursued by registered holding companies and their affiliates that operate in those states. Some of these frameworks attempt to regulate financing activities, acquisitions and divestitures, and arrangements between the utilities and their affiliates, and to restrict the level of non-utility business that can be conducted within the holding company structure. Additionally, they may impose record-keeping, record access, employee training and reporting requirements related to affiliate transactions and reporting in the event of certain downgrading of the utility's credit rating.

These regulatory frameworks could have adverse effects on our ability to conduct our utility operations, to finance our business and to provide cost-effective utility service. In addition, if more than one state adopts restrictions on similar activities, it may be difficult for us to comply with competing regulatory requirements.

Our businesses must compete with alternate energy sources, which could result in our marketing less natural gas, which could have an adverse impact on our results of operations, financial condition and cash flows.

We compete primarily with alternate energy sources such as electricity and other fuel sources. In some areas, intrastate pipelines, other natural gas distributors and marketers also compete directly with us for natural gas sales to end users. In addition, as a result of federal regulatory changes affecting interstate pipelines, natural gas marketers operating on these pipelines may be able to bypass our facilities and market, sell and/or transport natural gas directly to commercial and industrial customers. Any reduction in the amount of natural gas marketed, sold or transported by us as a result of competition may have an adverse impact on our results of operations, financial condition and cash flows.

Risk Factors Affecting Our Interests in Enable Midstream Partners, LP

We hold a substantial limited partnership interest in Enable (54.1% of Enable's outstanding limited partnership interests as of December 31, 2016), as well as 50% of the management rights in Enable's general partner and a 40% interest in the incentive distribution rights held by Enable's general partner. As of December 31, 2016, CenterPoint Energy owned an aggregate of 14,520,000 Series A Preferred Units in Enable. Accordingly, our future earnings, results of operations, cash flows and financial condition will be affected by the performance of Enable, the amount of cash distributions we receive from Enable and the value of our interests in Enable. Factors that may have a material impact on Enable's performance and cash distributions, and, hence, the value of our interests in Enable, include the risk factors outlined below, as well as the risks described elsewhere under "Risk Factors" that are applicable to Enable.

Our cash flows will be adversely impacted if we receive less cash distributions from Enable than we currently expect.

Both CERC Corp. and OGE hold their limited partnership interests in Enable in the form of both common units and subordinated units. Enable is expected to pay a minimum quarterly distribution of $0.2875 per unit, or $1.15 per unit on an annualized basis, on its outstanding common and subordinated units to the extent it has sufficient cash from operations after establishment of cash reserves and payment of fees and expenses, including payments to its general partner and its affiliates (referred to as "available cash"). The principal difference between Enable's common units and subordinated units is that in any quarter during the applicable subordination period, holders of the subordinated units are not entitled to receive any distribution of available cash until the common units have received the minimum quarterly distribution plus any arrearages in the payment of the minimum quarterly distribution on common units from prior quarters. If Enable does not pay distributions on its subordinated units, its subordinated units will not accrue arrearages for those unpaid distributions. Accordingly, if Enable is unable to pay its minimum quarterly distribution, the amount of cash distributions we receive from Enable may be adversely affected. Enable may not have sufficient available cash each quarter to enable it to pay the minimum quarterly distribution. The amount of cash Enable can distribute on its common and subordinated units will principally depend upon the amount of cash it generates from its operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees and gross margins it realizes with respect to the volume of natural gas, NGLs and crude oil that it handles;
- the prices of, levels of production of, and demand for natural gas, NGLs and crude oil;
- the volume of natural gas, NGLs and crude oil it gathers, compresses, treats, dehydrates, processes, fractionates, transports and stores;
- 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 its operation and maintenance expenses and general and administrative costs; and
- prevailing economic conditions.

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

- the level and timing of its capital expenditures;
- the cost of acquisitions;
- its debt service requirements and other liabilities;
- fluctuations in its working capital needs;
- its ability to borrow funds and access capital markets;
- restrictions contained in its debt agreements;
- the amount of cash reserves established by its general partner;
- distributions paid on its Series A Preferred Units; and
- other business risks affecting its cash levels.

The amount of cash Enable has available for distribution to us on its common and subordinated units depends primarily on its cash flow rather than on its profitability, which may prevent Enable from making distributions, even during periods in which Enable records net income.

The amount of cash Enable has available for distribution on its common and subordinated units depends primarily upon its cash flows and not solely on profitability, which will be affected by non-cash items. As a result, Enable may make cash distributions during periods when it records losses for financial accounting purposes and may not make cash distributions during periods when it records net earnings for financial accounting purposes.

We are not able to exercise control over Enable, which entails certain risks.

Enable is controlled jointly by CERC Corp. and OGE, who each own 50% of the management rights in the general partner of Enable. The board of directors of Enable's general partner is composed of an equal number of directors appointed by OGE and by us, the president and chief executive officer of Enable's general partner and three directors who are independent as defined under the independence standards established by the NYSE. Accordingly, we are not able to exercise control over Enable**.**

Although we jointly control Enable with OGE, we may have conflicts of interest with Enable that could subject us to claims that we have breached our fiduciary duty to Enable and its unitholders.

CERC Corp. and OGE each own 50% of the management rights in Enable's general partner, as well as limited partnership interests in Enable, and interests in the incentive distribution rights held by Enable's general partner. Conflicts of interest may arise between us and Enable and its unitholders. Our joint control of the general partner of Enable may increase the possibility of claims of breach of fiduciary duties including claims of conflicts of interest related to Enable. In resolving these conflicts, we may favor our own interests and the interests of our affiliates over the interests of Enable and its unitholders as long as the resolution does not conflict with Enable's partnership agreement. These circumstances could subject us to claims that, in favoring our own interests and those of our affiliates, we breached a fiduciary duty to Enable or its unitholders.

Enable's contracts are subject to renewal risks.

As contracts with its existing suppliers and customers expire, Enable may have to negotiate extensions or renewals of those contracts or enter into new contracts with other suppliers and customers. Enable may be unable to extend or renew existing contracts or enter into new contracts on favorable commercial terms, if at all. Depending on prevailing market conditions at the time of an extension or renewal, gathering and processing customers with fee based contracts may desire to enter into contracts under different fee arrangements. Approximately 87% of Enable’s gross margin was generated from fee-based contracts during the year ended December 31, 2016. Likewise, Enable’s transportation and storage customers may choose not to extend or renew expiring contracts based on the economics of the related areas of production. To the extent Enable is unable to renew or replace its expiring contracts on terms that are favorable, if at all, or successfully manage its overall contract mix over time, its financial position, results of operations and ability to make cash distributions could be adversely affected.

Enable depends on a small number of customers for a significant portion of its gathering and processing services revenues and its transportation and storage services revenues. The loss of, or reduction in volumes from, these customers could result in a decline in sales of its gathering and processing or transportation and storage services and adversely affect its financial position, results of operations and ability to make cash distributions.

For the year ended December 31, 2016, 49% of Enable’s gathered natural gas volumes were attributable to the affiliates of Continental, Vine, GeoSouthern, XTO Energy and Apache and 51% of its transportation and storage service revenues were attributable to affiliates of CenterPoint Energy, Spire, XTO Energy, American Electric Power Company and OGE.

The loss of all or even a portion of the gathering and processing or 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 Enable’s financial position, results of operations and ability to make cash distributions.

Enable’s businesses are dependent, in part, on the drilling and production decisions of others.

Enable’s businesses are dependent on the drilling and production of natural gas and crude oil. Enable has no control over the level of drilling activity in its areas of operation, or the amount of natural gas, NGL or crude oil reserves associated with wells connected to its systems. In addition, as the rate at which production from wells currently connected to its systems naturally declines over time, Enable’s gross margin associated with those wells will also decline. To maintain or increase throughput levels on its gathering and transportation systems and the asset utilization rates at its natural gas processing plants, Enable’s customers must continually obtain new natural gas, NGL and crude oil supplies. The primary factors affecting Enable’s ability to obtain new supplies of natural gas, NGLs and crude oil and attract new customers to its assets are the level of successful drilling activity near its systems, its ability to compete for volumes from successful new wells and its ability to expand its capacity as needed. If Enable is not able to obtain new supplies of natural gas, NGLs and crude oil to replace the natural decline in volumes from existing wells, throughput on its gathering, processing, transportation and storage facilities will decline, which could adversely affect its financial position, results of operations and ability to make cash distributions. Enable has 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, NGL and crude oil reserves. Drilling and production activity generally decreases as commodity prices decrease. In general terms, the prices of natural gas, NGLs, 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 Enable’s control. Because of these factors, even if new natural gas, NGL or crude oil reserves are known to exist in areas served by Enable’s assets, producers may choose not to develop those reserves. Declines in natural gas, NGL 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. In early 2016, natural gas and crude oil prices dropped to their lowest levels in over 10 years. Both natural gas and crude oil prices increased moderately in the second half of 2016. Sustained low natural gas, NGL or crude oil prices could also lead producers to shut in production from their existing wells. Sustained reductions in exploration or production activity in Enable's areas of operation could lead to further reductions in the utilization of its systems, which could adversely affect Enable's financial position, results of operations and ability to make cash distributions.

In addition, it may be more difficult to maintain or increase the current volumes on Enable's gathering systems and processing plants, as several of the formations in the unconventional resource plays in which it operates generally have higher initial production rates and steeper production decline curves than wells in more conventional basins. Should Enable determine that the economics of its gathering assets do not justify the capital expenditures needed to grow or maintain volumes associated therewith, Enable 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 Enable to incur higher maintenance capital expenditures relative to throughput over time, which will reduce its distributable cash flow.

Because of these and other factors, even if new reserves are known to exist in areas served by Enable's assets, producers may choose not to develop those reserves. Reductions in drilling activity would result in Enable's inability to maintain the current levels of throughput on its systems and could adversely affect its financial position, results of operations and ability to make cash distributions.

Enable's industry is highly competitive, and increased competitive pressure could adversely affect its financial position, results of operations and ability to make cash distributions.

Enable competes with similar enterprises in its respective areas of operation. The principal elements of competition are rates, terms of service and flexibility and reliability of service. Enable's competitors include large energy companies that have greater financial resources and access to supplies of natural gas, NGLs and crude oil than Enable. Some of these competitors may expand or construct gathering, processing, transportation and storage systems that would create additional competition for the services Enable provides to its customers. Excess pipeline capacity in the regions served by Enable's interstate pipelines could also increase competition and adversely impact Enable's ability to renew or enter into new contracts with respect to its available capacity when existing contracts expire. In addition, Enable's customers that are significant producers of natural gas or crude oil may develop their own gathering, processing, transportation and storage systems in lieu of using Enable's systems. Enable's ability to renew or replace existing contracts with its customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of its 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 storage services. All of these competitive pressures could adversely affect Enable's financial position, results of operations and ability to make cash distributions.

Enable may not be able to recover the costs of its substantial planned investment in capital improvements and additions, and the actual cost of such improvements and additions may be significantly higher than it anticipates.

Enable's business plan calls for investment in capital improvements and additions. In Enable's Form 10-K for the year ended December 31, 2016, Enable stated that it expects that its expansion capital could range from approximately $455 million to $575 million and its maintenance capital could range from approximately $95 million to $125 million for the year ending December 31, 2017. In the second quarter of 2016, Enable delayed the completion of the Wildhorse Plant, a cryogenic processing facility that it plans to connect to its super-header system in Garvin County, Oklahoma. Enable also plans to construct natural gas gathering and compression infrastructure to support producer activity.

The construction of additions or modifications to Enable's existing systems, and the construction of new midstream assets, involves numerous regulatory, environmental, political and legal uncertainties, many of which are beyond Enable's control and may require the expenditure of significant amounts of capital, which may exceed its 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, Enable's revenues and cash flows may not increase immediately upon the expenditure of funds on a particular project. For instance, if Enable expands an existing pipeline or constructs a new pipeline, the construction may occur over an extended period of time, and Enable may not receive any material increases in revenues or cash flows until the project is completed. In addition, Enable 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 Enable's expected investment return, which could adversely affect its financial position, results of operations and ability to make cash distributions.

In connection with Enable's capital investments, Enable may estimate, or engage a third party to estimate, potential reserves in areas to be developed prior to constructing facilities in those areas. To the extent Enable relies on estimates of future production in deciding to construct additions to its 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 Enable's financial position, results of operations and ability to make cash distributions. In addition, the construction 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 Enable 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, Enable's financial position, results of operations and ability to make cash distributions could be adversely affected.

Natural gas, NGL and crude oil prices are volatile, and changes in these prices could adversely affect Enable's financial position, results of operations and ability to make cash distributions.

Enable's financial position, results of operations and ability to make cash distributions could be negatively affected by adverse movements in the prices of natural gas, NGLs and crude oil depending on factors that are beyond Enable's 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. In early 2016, natural gas and crude oil prices dropped to their lowest levels in over 10 years. Both natural gas and crude oil prices increased moderately in the second half of 2016.

Enable's natural gas processing arrangements expose it to commodity price fluctuations. In 2016, 8%, 46%, and 46% of Enable's processing plant inlet volumes consisted of keep-whole arrangements, percent-of-proceeds or percent-of-liquids and fee-based, respectively. Under a typical keep-whole arrangement, Enable processes raw natural gas, extracts the NGLs, replaces the extracted NGLs with a Btu equivalent amount of natural gas, delivers the processed and replacement natural gas to the producer, retains the NGLs and sells the NGLs for its own account. If Enable is unable to sell the NGLs extracted for more than the cost of the replacement natural gas, the margins on its sale of goods will be negatively affected.

Under a typical percent-of-proceeds processing arrangement, Enable purchases raw natural gas at a cost that is based on the amount of natural gas and NGLs contained in the raw natural gas. Enable then processes the raw natural gas, extracts the NGLs and sells the processed natural gas and NGLs for its own account. If Enable is unable to sell the processed natural gas and NGLs for more than the cost of the raw natural gas, the margins on its sale of goods will be negatively affected.

Under a typical percent-of-liquids processing arrangement and a typical fee-based arrangement, Enable purchases a portion of the raw natural gas that is equivalent to the amount of NGLs it contains, processes the raw natural gas, extracts the NGLs, returns the processed natural gas to the producer and sells the NGLs for its own account. If Enable is unable to sell the processed natural gas and NGLs for more than the cost of raw natural gas, the margins on its sale of goods will be negatively affected.

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

Enable is exposed to credit risks of its customers, and any material nonpayment or nonperformance by its key customers could adversely affect its financial position, results of operations and ability to make cash distributions.

Some of Enable's customers may experience financial problems that could have a significant effect on their creditworthiness. Severe financial problems encountered by its customers could limit Enable's ability to collect amounts owed to it, or to enforce performance of obligations under contractual arrangements. In addition, many of Enable's customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. The combination of reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under reserve-based credit facility and the lack of availability of debt or equity financing may result in a significant reduction of its customers' liquidity and limit their ability to make payment or perform on their obligations to Enable. Furthermore, some of Enable's customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to Enable. Financial problems experienced by Enable's customers could result in the impairment of its assets, reduction of its operating cash flows and may also reduce or curtail their future use of its products and services, which could reduce Enable's revenues.

Enable provides certain transportation and storage services under fixed-price "negotiated rate" contracts that are not subject to adjustment, even if its cost to perform such services exceeds the revenues received from such contracts, and, as a result, Enable's costs could exceed its revenues received under such contracts.

Enable has been authorized by the FERC to provide transportation and storage services at its facilities at negotiated rates. Generally, negotiated rates are in excess of the maximum recourse rates allowed by the 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 Enable's systems and, therefore, decrease the cash it has available for distribution.

As of December 31, 2016, approximately 54% of Enable's contracted firm transportation capacity and 44% of its contracted firm storage 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 the 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 Enable's gathering, processing or transportation facilities become partially or fully unavailable for any reason, Enable's financial position, results of operations and ability to make cash distributions could be adversely affected.

Enable depends upon third-party pipelines to deliver natural gas to, and take natural gas from, its natural gas transportation systems and upon third-party pipelines to take crude oil from its crude oil gathering systems. Enable also depends on third-party facilities to transport and fractionate NGLs that are delivered to the third party at the tailgates of Enable's 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 Enable's processing plants and gathering systems, and a prolonged outage or disruption could ultimately result in a reduction in the volume of natural gas Enable gathers and NGLs it is able to produce. Additionally, Enable depends on third parties to provide electricity for compression at many of its facilities. Since Enable does not own or operate any of these third-party pipelines or other facilities, their continuing operation is not within its control. If any of these third-party pipelines or other facilities become partially or fully unavailable for any reason, Enable's financial position, results of operations and ability to make cash distributions could be adversely affected.

Enable does not own all of the land on which its pipelines and facilities are located, which could disrupt its operations.

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

Enable conducts a portion of its operations through joint ventures, which subject it to additional risks that could adversely affect the success of these operations and Enable's financial position, results of operations and ability to make cash distributions.

Enable conducts a portion of its operations through joint ventures with third parties, including Spectra Energy Partners, LP, DCP Midstream Partners, LP, Trans Louisiana Gas Pipeline, Inc. and Pablo Gathering LLC. Enable 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 Enable's control. If these parties do not satisfy their obligations under these arrangements, Enable's business may be adversely affected.

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

- Enable's joint venture partners may share certain approval rights over major decisions;

- Enable’s joint venture partners may not pay their share of the joint venture’s obligations, leaving Enable liable for their shares of joint venture liabilities;

- Enable may be unable to control the amount of cash it will receive from the joint venture;

- Enable may incur liabilities as a result of an action taken by its joint venture partners;

- Enable may be required to devote significant management time to the requirements of and matters relating to the joint ventures;

- Enable’s insurance policies may not fully cover loss or damage incurred by both Enable and its joint venture partners in certain circumstances;

- Enable’s joint venture partners may be in a position to take actions contrary to its instructions or requests or contrary to its policies or objectives; and

- disputes between Enable and its joint venture partners may result in delays, litigation or operational impasses.

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

Enable’s ability to grow is dependent on its ability to access external financing sources.

Enable expects that it will distribute all of its “available cash” to its unitholders. As a result, Enable is expected to 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 Enable is unable to finance growth externally, Enable’s cash distribution policy will significantly impair its ability to grow. In addition, because Enable is expected to distribute all of its available cash, its growth may not be as fast as businesses that reinvest their available cash to expand ongoing operations.

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

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

Enable’s debt levels may limit its flexibility in obtaining additional financing and in pursuing other business opportunities.

As of December 31, 2016, Enable had approximately $3.0 billion of long-term debt outstanding, excluding the premiums on their senior notes. Enable has a $1.75 billion revolving credit facility for working capital, capital expenditures and other partnership purposes, including acquisitions, of which $1.1 billion was available as of February 1, 2017. Enable will continue to have the ability to incur additional debt, subject to limitations in its credit facilities. The levels of Enable’s 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;

- Enable's debt level will make it more vulnerable to competitive pressures or a downturn in its business or the economy generally; and

- Enable's debt level may limit its flexibility in responding to changing business and economic conditions.

Enable's ability to service its debt will depend upon, among other things, its future financial and operating performance, which will be affected by prevailing economic conditions, commodity prices and financial, business, regulatory and other factors, some of which are beyond Enable's control. If operating results are not sufficient to service current or future indebtedness, Enable 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.

Enable's credit facilities contain operating and financial restrictions, including covenants and restrictions that may be affected by events beyond Enable's control, which could adversely affect its financial condition, results of operations and ability to make distributions.

Enable's credit facilities contain customary covenants that, among other things, limit its ability to:

- permit its 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 its business.

Enable's credit facilities also require it to maintain certain financial ratios. Enable's ability to meet those financial ratios can be affected by events beyond its control, and we cannot assure you that it will meet those ratios. In addition, Enable's credit facilities contain events of default customary for agreements of this nature.

Enable's ability to comply with the covenants and restrictions contained in its credit facilities may be affected by events beyond its control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, Enable's ability to comply with these covenants may be impaired. If Enable violates any of the restrictions, covenants, ratios or tests in its credit facilities, a significant portion of its indebtedness may become immediately due and payable. In addition, Enable's lenders' commitments to make further loans to it under the revolving credit facility may be suspended or terminated. Enable might not have, or be able to obtain, sufficient funds to make these accelerated payments.

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

Performance of Enable's operations require that Enable obtains and maintains 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 Enable's 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 Enable's ability to initiate or continue operations at the affected location or facility and on its financial condition, results of operations and ability to make cash distributions.

Additionally, in order to obtain permits and renewals of permits and other approvals in the future, Enable 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 Enable's financial position, results of operations and ability to make cash distributions.

Enable is 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 its costs of construction, restrict or limit the output of certain facilities and/or require additional pollution control equipment and otherwise increase costs. For instance, in May 2016, the EPA issued final New Source Performance Standards governing methane emissions imposing more stringent controls on methane and volatile organic compounds emissions at new and modified oil and natural gas production, processing, storage and transmission facilities. These rules have required changes to Enable's operations, including the installation of new equipment to control emissions. The EPA has also announced that it intends to impose methane emission standards for existing sources and has issued information collection requests to companies with production, gathering and boosting, gas processing, storage, and transmission facilities. Additionally, several states are pursuing similar measures to regulate emissions of methane from new and existing sources. There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations. As a result of this continued regulatory focus, future federal and state regulations relating to Enable's gathering and processing, transmission, and storage operations remain a possibility and could result in increased compliance costs on its operations. Furthermore, if new or more stringent federal, state or local legal restrictions are adopted in areas where Enable's 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 could adversely affect demand for Enable's services to those customers.

There is inherent risk of the incurrence of environmental costs and liabilities in Enable's operations due to its handling of natural gas, NGLs, crude oil and produced water, as well as air emissions related to its operations and historical industry operations and waste disposal practices. These matters 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 Enable's business activities in many ways, such as restricting the way it can handle or dispose of wastes or requiring remedial action to mitigate pollution conditions that may be caused by its 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 Enable's properties and facilities, many of which have been used for midstream activities for a number of years, oftentimes by third parties not under its control. Private parties, including the owners of the properties through which Enable's gathering systems pass and facilities where its 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 Enable's pipelines could subject it 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. Enable 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 Enable's customers' production and operations, resulting in less demand for its services.

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production by Enable's customers, which could adversely affect its financial position, results of operations and ability to make cash distributions.

Hydraulic fracturing is common practice that is used by many of Enable's customers to stimulate production of natural gas and crude 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. 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 May 2016, the EPA issued final new source performance standard requirements that impose more stringent controls on methane and volatile organic compounds emissions from oil and gas development and production operations, including hydraulic fracturing and other well completion activity. The EPA also released the final results of its comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on drinking water resources in December 2016. The EPA concluded that hydraulic fracturing activities can impact drinking water resources under some circumstances, including large volume spills and inadequate mechanical integrity of wells. The results of EPA's study could spur action towards federal legislation and regulation of hydraulic fracturing or similar production operations. In past sessions, Congress has considered, but not passed, legislation to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and to require disclosure of the chemicals used in the hydraulic fracturing process. The EPA has issued the Safe Water Drinking Act permitting guidance for hydraulic fracturing operations involving the use of diesel fuel in fracturing fluids in those states where the EPA is the permitting authority. Additionally, the Bureau of Land Management issued final rules to regulate hydraulic fracturing on federal lands in March 2015. Although these rules were struck down by a federal court in Wyoming in June 2016, an appeal of the decision is still pending.

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 entirely. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where Enable's 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 Enable's services to those customers.

State and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste disposal and seismic activity. Similar concerns have been raised that hydraulic fracturing may also contribute to seismic activity. When caused by human activity, such events are called induced seismicity. In March 2016, the United States Geological Survey identified six states with the most significant hazards from induced seismicity, including Oklahoma, Kansas, Texas, Colorado, New Mexico and Arkansas. In light of these concerns, some state regulatory agencies have modified their regulations or issued orders to address induced seismicity. For example, the OCC has implemented volume reduction plans, and at times required shut-ins, for disposal wells injecting wastewater from oil and gas operations into the Arbuckle formation. The OCC also recently released well completion seismicity guidelines for operators in the South Central Oklahoma Oil Province and the Sooner Trend Anadarko Basin Canadian and Kingfisher Counties that call for hydraulic fracturing operations to be suspended following earthquakes of certain magnitudes in the vicinity. Certain environmental and other groups have also suggested that additional federal, state and local laws and regulations may be needed to more closely regulate the hydraulic fracturing process. Enable cannot predict whether additional federal, state or local laws or regulations applicable to hydraulic fracturing will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. Increased regulation and attention given to induced seismicity could lead to greater opposition to, and litigation concerning, oil and gas activities utilizing hydraulic fracturing or injection wells for waste disposal. Additional legislation or regulation could also lead to operational delays or increased operating costs for Enable's customers, which in turn could reduce the demand for Enable's services.

Other governmental agencies, including the DOE, 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 Safe Drinking Water Act or other regulatory mechanisms.

Enable's operations are subject to extensive regulation by federal, state and local regulatory authorities. Changes or additional regulatory measures adopted by such authorities could adversely affect Enable's financial position, results of operations and ability to make cash distributions.

The rates charged by several of Enable's pipeline systems, including for interstate gas transportation service provided by its intrastate pipelines, are regulated by the FERC. Enable's pipeline operations that are not regulated by the FERC may be subject to state and local regulation applicable to intrastate natural and transportation services. The relevant states in which Enable operates include North Dakota, Oklahoma, Arkansas, Louisiana, Texas, Missouri, Kansas, Mississippi, Tennessee and Illinois.

The FERC and state regulatory agencies also regulate other terms and conditions of the services Enable may offer. If one of these regulatory agencies, on its own initiative or due to challenges by third parties, were to lower its tariff rates or deny any rate increase or other material changes to the types, or terms and conditions, of service Enable might propose or offer, the profitability of Enable's pipeline businesses could suffer. If Enable were permitted to raise its 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 its profitability. Furthermore, competition from other pipeline systems may prevent Enable from raising its tariff rates even if regulatory agencies permit it to do so. The regulatory agencies that regulate Enable's 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 Enable's services or otherwise adversely affect its financial position, results of operations and cash flows and ability to make cash distributions.

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

Enable's natural gas gathering and intrastate transportation operations are generally exempt from the jurisdiction of the FERC under the NGA, but FERC regulation may indirectly impact these businesses and the markets for products derived from these businesses. The 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, the FERC has pursued pro-competitive policies in its regulation of interstate oil and natural gas pipelines. However, we cannot assure you that the 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 the FERC has not made a formal determination with respect to all of Enable's facilities it considers to be gathering facilities, Enable believes that its natural gas gathering pipelines meet the traditional tests that the 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 the FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of Enable's 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 Enable's financial condition, results of operations and ability to make cash distributions. In addition, if any of Enable's facilities were found to have provided services or otherwise operated in violation of the NGA or the 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 the FERC.

Natural gas gathering may receive greater regulatory scrutiny at the state level; therefore, Enable's natural gas gathering operations could be adversely affected should they become subject to the application of state regulation of rates and services. Enable's 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 Enable's operations, but Enable could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Other Risk Factors Affecting Our Businesses or Our Interests in Enable Midstream Partners, LP

We are subject to operational and financial risks and liabilities arising from environmental laws and regulations.

Our operations and the operations of Enable are subject to stringent and complex laws and regulations pertaining to the environment. As an owner or operator of natural gas pipelines, distribution systems and storage, and the facilities that support these systems, we must comply with these laws and regulations at the federal, state and local levels. 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;
- limiting or prohibiting construction activities in sensitive areas such as wetlands, coastal regions, or areas inhabited by endangered species;
- requiring remedial action to mitigate environmental conditions caused by our operations, or attributable to former operations;
- enjoining the operations of facilities with permits issued pursuant to such environmental laws and regulations; and
- impacting the demand for our services by directly or indirectly affecting the use or price of natural gas.

To comply with these requirements, we may need to spend substantial amounts and devote other resources from time to time to:

- construct or acquire new facilities and equipment;

- acquire permits for facility operations;
- modify or replace existing and proposed equipment; and
- clean or decommission waste management areas, fuel storage facilities and other locations.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial actions, and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean and restore sites where hazardous substances have been stored, disposed or released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

The recent trend in environmental regulation has been to place more restrictions and limitations on activities that may impact the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be greater than the amounts we currently anticipate.

Our insurance coverage may not be sufficient. Insufficient insurance coverage and increased insurance costs could adversely impact our results of operations, financial condition and cash flows.

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 and do not include business interruption coverage. 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, financial condition and cash flows.

Our operations and Enable’s 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, NGLs, crude oil and other hydrocarbons or losses of natural gas, NGLs 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.

Enable currently has general liability and property insurance in place to cover certain of its facilities in amounts that Enable considers appropriate. Such policies are subject to certain limits and deductibles. Enable is not fully insured against all risks inherent in its business. 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 Enable’s operations. A natural disaster or other hazard affecting the areas in which Enable operates could have a material adverse effect on Enable’s operations. Enable does not have business interruption insurance coverage for all of its 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 Enable’s facilities may not be sufficient to restore the loss or damage without negative impact on its results of operations and its ability to make cash distributions.

We and CenterPoint Energy could incur liabilities associated with businesses and assets that we have transferred to others.

Under some circumstances, we and CenterPoint Energy could incur liabilities associated with assets and businesses we and CenterPoint Energy no longer own. These assets and businesses were previously owned by Reliant Energy, a predecessor of Houston Electric, directly or through subsidiaries and include:

- merchant energy, energy trading and REP businesses transferred to RRI or its subsidiaries in connection with the organization and capitalization of RRI prior to its initial public offering in 2001 and now owned by affiliates of NRG; and

- Texas electric generating facilities transferred to a subsidiary of Texas Genco in 2002, later sold to a third party and now owned by an affiliate of NRG.

In connection with the organization and capitalization of RRI (now GenOn) and Texas Genco (now an affiliate of NRG), those companies and/or their subsidiaries assumed liabilities associated with various assets and businesses transferred to them and agreed to certain indemnity agreements of CenterPoint Energy entities. Such indemnities have applied in cases such as the litigation arising out of sales of natural gas in California and other markets (the last remaining case involving CenterPoint Energy is now on appeal, following the district court's summary judgment in favor of CES, a subsidiary of CERC Corp.) and various asbestos and other environmental matters that arise from time to time. GenOn has publicly disclosed that it may be unable to continue as a going concern and is exploring various options, including negotiations with creditors and lessors, refinancing, potential sale of assets, as well as the possibility of filing for protection under Chapter 11 of the U.S. Bankruptcy Code. If any of the indemnifying entities were unable to meet their indemnity obligations or satisfy a liability that has been assumed or if claims in one or more of these lawsuits were successfully asserted against us, we, CenterPoint Energy or Houston Electric could incur liability and be responsible for satisfying the liability.

In connection with Houston Electric's sale of Texas Genco, the separation agreement was amended to provide that Texas Genco would no longer be liable for, and Houston Electric would assume and agree to indemnify Texas Genco against, liabilities that Texas Genco originally assumed in connection with its organization to the extent, and only to the extent, that such liabilities are covered by certain insurance policies held by Houston Electric, and in certain of the asbestos lawsuits Houston Electric has agreed to continue to defend such claims to the extent they are covered by insurance maintained by Houston Electric, subject to reimbursement of the costs of such defense by an NRG affiliate.

Cyber-attacks, physical security breaches, acts of terrorism or other disruptions could adversely impact our or Enable's results of operations, financial condition and/or cash flows.

We and Enable are subject to cyber and physical security risks related to adversaries attacking information technology systems, network infrastructure and facilities used to (i) manage operations and other business processes and (ii) protect sensitive information maintained in the normal course of business. Our and Enable's business operations are interconnected with external networks and facilities. The distribution of natural gas to our customers requires communications with Enable's pipeline facilities and third-party systems. The gathering, processing and transportation of natural gas from Enable's gathering, processing and pipeline facilities and crude oil gathering pipeline systems also rely on communications among its facilities and with third-party systems that may be delivering natural gas or crude oil into or receiving natural gas or crude oil and other products from Enable's 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 or Enable's ability to conduct operations and control assets.

Cyber-attacks and unauthorized access could also result in the loss of confidential, proprietary or critical infrastructure data or security breaches of other information technology systems that could disrupt operations and critical business functions, adversely affect reputation, increase costs and subject us or Enable to possible legal claims and liability. Neither we nor Enable is fully insured against all cyber-security risks, any of which could have a material adverse effect on either our, or Enable's, results of operations, financial condition and cash flows.

In addition, our and Enable's critical energy infrastructure may be targets of terrorist activities that could disrupt our respective business operations. Any such disruptions could result in significant costs to repair damaged facilities and implement increased security measures, which could have a material adverse effect on either our or Enable's results of operations, financial condition and cash flows.

Failure to maintain the security of personally identifiable information could adversely affect us.

In connection with our business we collect and retain personally identifiable information of our customers and employees. Our customers and employees expect that we will adequately protect their personal information, and the United States regulatory environment surrounding information security and privacy is increasingly demanding. A significant theft, loss or fraudulent use of customer, employee or CERC data by cyber-crime or otherwise could adversely impact our reputation and could result in significant costs, fines and litigation.

Our results of operations, financial condition and cash flows may be adversely affected if we are unable to successfully operate our facilities or perform certain corporate functions.

Our performance depends on the successful operation of our facilities. Operating these facilities involves many risks, including:

- operator error or failure of equipment or processes;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- information technology or financial system failures that impair our information technology infrastructure, reporting systems or disrupt normal business operations;
- information technology failure that affects our ability to access customer information or causes us to lose confidential or proprietary data that materially and adversely affects our reputation or exposes us to legal claims; and
- catastrophic events such as fires, earthquakes, explosions, leaks, floods, droughts, hurricanes, terrorism, pandemic health events or other similar occurrences.

Such events may result in a decrease or elimination of revenue from our facilities, an increase in the cost of operating our facilities or delays in cash collections, any of which could have a material adverse effect on our results of operations, financial condition and/or cash flows.

Our success depends upon our ability to attract, effectively transition and retain key employees and identify and develop talent to succeed senior management.

We depend on our senior executive officers and other key personnel. Our success depends on our ability to attract, effectively transition and retain key personnel. The inability to recruit and retain or effectively transition key personnel or the unexpected loss of key personnel may adversely affect our operations. In addition, because of the reliance on our management team, our future success depends in part on our ability to identify and develop talent to succeed senior management. The retention of key personnel and appropriate senior management succession planning will continue to be critically important to the successful implementation of our strategies.

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

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 skillsets to future needs, 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 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 the 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.

Climate change legislation and regulatory initiatives could result in increased operating costs and reduced demand for our services or Enable's services.

Regulatory agencies have from time to time considered adopting legislation, including modification of existing laws and regulations, to reduce GHGs, and there continues to be a wide-ranging policy and regulatory debate, both nationally and internationally, regarding the potential impact of GHGs and possible means for their regulation. Following a finding by the 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 that requires a reduction in emissions of GHGs from motor vehicles and another that regulates emissions of GHGs from certain large stationary sources. The EPA has also expanded its existing GHG emissions reporting requirements. These permitting and reporting requirements could lead to further regulation of GHGs by the EPA. As a distributor and transporter of natural gas, or a consumer of natural gas in its pipeline and gathering businesses, our or Enable's revenues, operating costs and capital requirements, as applicable, could be adversely affected as a result of any regulatory action that would require installation of new control technologies or a modification of its operations or would have the effect of reducing the consumption of natural gas. Likewise, incentives to conserve energy or use energy sources other than natural gas could result in a decrease in demand for our services.

Climate changes could result in more frequent and more severe weather events which could adversely affect the results of operations of our businesses.

To the extent climate changes occur, our businesses may be adversely impacted, though we believe any such impacts are likely to occur very gradually and hence would be difficult to quantify with specificity. To the extent global climate change results in warmer temperatures in our service territories, financial results from our natural gas distribution businesses could be adversely affected through lower gas sales, and Enable's natural gas gathering, processing and transportation and crude oil gathering businesses could experience lower revenues. Another possible result of climate change is more frequent and more severe weather events, such as hurricanes or tornadoes. Since many of our facilities are located along or near the Gulf Coast, increased or more severe hurricanes or tornadoes could increase our costs to repair damaged facilities and restore service to our customers. When we cannot deliver natural gas to customers or our customers cannot receive our services, our financial results can be impacted by lost revenues, and we generally must seek approval from regulators to recover restoration costs. To the extent we are unable to recover those costs, or if higher rates resulting from our recovery of such costs result in reduced demand for our services, our future financial results may be adversely impacted.

We may be negatively impacted by changes in federal income tax policy.

The Executive and Legislative Branches of the United States Federal government have made public statements in support of comprehensive tax reform plans, including significant changes to corporate income tax laws. We are currently unable to predict whether these reform discussions will result in any significant changes to existing tax laws, or if any such changes would have a cumulative positive or negative impact on us or our regulatory activities. It is possible that changes in the United States federal income tax laws could have an adverse effect on our or Enable's results of operations, financial condition, and cash flows.

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

The 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 pipeline operators, including us and Enable, to, among other things:

- perform ongoing assessments of pipeline integrity;
- 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;
- develop processes for performance management, record keeping, management of change and communication;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating action.

Recent regulatory proposals from PHMSA would expand the scope of its safety, reporting and recordkeeping requirements for both natural gas and hazardous liquids (including crude oil and NGLs) pipelines, as well as underground natural gas storage facilities. These proposals, if finalized, would impose additional costs on us and Enable.

In March 2016, PHMSA issued a notice of proposed rulemaking detailing proposed revisions to the safety standards applicable to natural gas transmission and gathering pipelines. The proposed rules include significant modifications which, if adopted, will result in significant operational and integrity management changes. These include requiring reconfirmation of the Maximum Allowable Operating Pressures in pipelines without reliable records, creating new material verification procedures, adding a new moderate consequence area, and tightening repair criteria for pipelines in both high and moderate consequence areas. Other modifications include adding record-keeping and data collection obligations, and new requirements for monitoring gas quality and managing corrosion. The proposed rules also would expand the scope of gas gathering lines subject to PHMSA regulation, including imposing minimum safety standards on certain larger, currently exempt, gathering lines, while subjecting all gathering-line operators to recordkeeping and annual reporting requirements from which they are currently exempt. Other proposed changes, such as the modification to the definition of a transmission line, some record-keeping requirements, and some material verification obligations also may impact distribution pipelines although PHMSA states that such far-reaching applicability is not its intent. PHMSA is currently reviewing thousands of public comments submitted in July 2016. Because the impact of these proposed rules remains uncertain, we are still monitoring and evaluating the effect of these proposed requirements.

PHMSA also issued a similar notice of proposed rulemaking for hazardous liquid pipelines in October 2015. Both of these notices of proposed rulemaking would require inspections of pipeline areas affected by severe weather, natural disasters or similar events. In addition, the proposed hazardous liquid rule would extend PHMSA reporting requirements to all gathering lines, require periodic inline inspections of pipelines outside of high consequence areas, require use of leak detection systems on all hazardous liquid pipelines, modify applicable repair criteria and set a timeline for pipelines subject to integrity management requirements to be capable of accommodating inline inspection tools. PHMSA issued the final rule for hazardous liquid pipelines on January 13, 2017, but the rule's eventual implementation and effectiveness are uncertain as a result of a January 20, 2017 regulatory freeze. We will continue to monitor the status of this rulemaking and the effect of these proposed requirements on operations.

On December 14, 2016, PHMSA announced an interim final rule to impose industry-developed recommendations as enforceable safety standards for downhole (underground) equipment, including wells, wellbore tubing, and casing, at both interstate and intrastate underground natural gas storage facilities. This rule went into effect on January 18, 2017, with a compliance deadline of January 18, 2018. Both CERC and Enable own and operate underground storage facilities that will be subject to this rule's provisions, which include procedures and practices for operations, maintenance, threat identification, monitoring, assessment, site security, emergency response and preparedness, training and recordkeeping. States may also impose more stringent standards on intrastate storage facilities. CERC and Enable continue to assess the potential impact of this newly announced rule.

Although many of our and Enable's pipelines fall within a class that is currently not subject to the requirements in PHMSA's recent proposals, they may nonetheless incur significant cost and liabilities associated with repair, remediation, prevention or mitigation measures associated with their non-exempt pipelines, which are subject to existing requirements. Work associated with PHMSA requirements is part of our and Enable's normal integrity management program and neither expect to incur any extraordinary costs during 2017 to complete the testing required by existing DOT regulations and their state counterparts. We and Enable 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 their pipelines during the pendency of such repairs. Should we or Enable fail to comply with DOT or comparable state regulations, we could be subject to penalties and fines.

Aging infrastructure may lead to increased costs and disruptions in operations that could negatively impact our financial results.

We have risks associated with aging infrastructure assets. The age of certain of our assets may result in a need for replacement, or higher level of maintenance costs as a result of our risk based federal and state compliant integrity management programs. Failure to achieve timely recovery of these expenses could adversely impact revenues and could result in increased capital expenditures or expenses.

The operation of our facilities depends on good labor relations with our employees.

Several of our businesses have entered into and have in place collective bargaining agreements with different labor unions. We have six separate bargaining units, each with a unique collective bargaining agreement. In 2016, we entered into two renegotiated collective bargaining agreements with Professional Employees International Union Local 12, which are scheduled to expire in 2021. Two collective bargaining agreements with United Steelworkers Local 227 and United Steelworkers Local 13-1 are scheduled to expire in June and July of 2017, respectively. The collective bargaining agreements with Gas Workers Union, Local 340 and the IBEW Local 949 are scheduled to expire in April and December of 2020, respectively. Any failure to reach an agreement on new labor contracts or to negotiate these labor contracts might result in strikes, boycotts or other labor disruptions. These potential labor disruptions could have a material adverse effect on our businesses, results of operations and/or cash flows. Labor disruptions, strikes or significant negotiated wage and benefit increases, whether due to union activities, employee turnover or otherwise, could have a material adverse effect on our businesses, results of operations and/or cash flows.

Our businesses will continue to have to adapt to technological change and may not be successful or may have to incur significant expenditures to adapt to technological change.

We operate in businesses that require sophisticated data collection, processing systems, software and other technology. Some of the technologies supporting the industries we serve are changing rapidly. We expect that new technologies will emerge or grow that may be superior to, or may not be compatible with, some of our existing technologies, and may require us to make significant expenditures so that we can continue to provide cost-effective and reliable methods of energy delivery.

Our future success will depend, in part, on our ability to anticipate and adapt to these technological changes in a cost-effective manner and to offer, on a timely basis, reliable services that meet customer demands and evolving industry standards. If we fail to adapt successfully to any technological change or obsolescence, or fail to obtain access to important technologies or incur significant expenditures in adapting to technological change, our businesses, operating results, financial condition and cash flows could be materially and adversely affected.

Our or Enable’s potential business strategies and strategic initiatives, including merger and acquisition activities and the disposition of assets or businesses, may not be completed or perform as expected.

From time to time, we and Enable have made and may continue to make acquisitions or divestitures of businesses and assets, form joint ventures or undertake restructurings. However, suitable acquisition candidates or potential buyers may not continue to be available on terms and conditions we or Enable, as the case may be, find acceptable, or the expected benefits of completed acquisitions may not be realized fully or at all, or may not be realized in the anticipated timeframe. If we or Enable are unable to make acquisitions or if those acquisitions do not perform as anticipated, our and Enable’s future growth may be adversely affected.

Any completed or future 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 or Enable 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 or Enable 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 ongoing businesses, distract management, divert resources and make it difficult to maintain current business standards, controls and procedures.

For example, the success of our acquisitions of Continuum and AEM will depend, in part, on our ability to realize the expected benefits, including operating efficiencies, cost savings and customer retention, from integrating Continuum and AEM’s energy services businesses with its existing energy services business. The integration process could be costly and time consuming and may result in the following challenges, among others:

- unanticipated disruptions, issues or costs in integrating financial and accounting, information technology, communications and other systems;
- potential inconsistencies in procedures, practices, policies, controls, and standards;
- possible differences in compensation arrangements, management perspectives and corporate culture; and
- loss of or difficulties retaining valuable employees or third-party relationships.

Even with the successful integration of the businesses, we may not achieve the expected results. We anticipate that our acquisitions of Continuum and AEM will be accretive to earnings in 2017. Any of the factors addressed above could decrease or delay the projected accretive effect of the transaction. Failure to fully realize the expected benefits could adversely affect our results of operations, financial condition and cash flows.

In addition, on February 1, 2016, we announced that we were evaluating strategic alternatives for our investment in Enable, including a sale or spin-off qualifying under Section 355 of the U.S. Internal Revenue Code. We continue to evaluate various options for our investment in Enable. However, there can be no assurance that this evaluation will result in any specific action.

We are involved in numerous legal proceedings, the outcome of which are uncertain, and resolutions adverse to us could negatively affect our financial results.

We are subject to numerous legal proceedings, the most significant of which are summarized in Note 14 of the consolidated financial statements. Litigation is subject to many uncertainties, and we cannot predict the outcome of individual matters with assurance. Final resolution of these matters may require additional expenditures over an extended period of time that may be in excess of established reserves and may have a material adverse effect on our financial results.

We are exposed to risks related to reduction in energy consumption due to factors including unfavorable economic conditions in our service territories, energy efficiency initiatives and use of alternative technologies.

Our businesses are affected by reduction in energy consumption due to factors including economic climate in our service territories, energy efficiency initiatives and use of alternative technologies, which could impact our ability to grow our customer base and our rate of growth. Prolonged economic downturns that negatively impact our results of operations and cash flows could result in future material impairment charges to write-down the carrying value of certain assets, including goodwill, to their respective fair values.

For example, we conduct business in Houston, Texas, where a higher percentage of employment is tied to the energy sector relative to other regions of the country. Given the significant decline in energy and commodity prices in 2015 and 2016, and resulting low commodity prices which we expect to continue in 2017, the rate of growth in employment in Houston has declined. In the event economic conditions further decline, the rate of growth in Houston and the other areas in which we operate may also deteriorate. Increases in customer defaults or delays in payment due to liquidity constraints could negatively impact our cash flows and financial condition.

Growth in customer accounts and growth of customer usage each directly influence demand for natural gas and the need for additional delivery facilities. Customer growth and customer usage are affected by a number of factors outside our control, such as mandated energy efficiency measures, demand-side management goals and economic and demographic conditions, such as population changes, job and income growth, housing starts, new business formation and the overall level of economic activity.

Certain regulatory and legislative bodies have introduced or are considering requirements and/or incentives to reduce energy consumption by certain dates. Additionally, technological advances driven by federal laws mandating new levels of energy efficiency in end-use electric devices or other improvements in or applications of technology could lead to declines in per capita energy consumption.

Some or all of these factors, could result in a lack of growth or decline in customer demand for electricity or number of customers, and may result in our failure to fully realize anticipated benefits from significant capital investments and expenditures which could have a material adverse effect on their financial position, results of operations and cash flows.

Furthermore, we currently have energy efficiency riders in place to recover the cost of energy efficiency programs. Should we be required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact.

If we fail to maintain an effective system of internal controls, our ability to accurately report our financial condition, results of operations or cash flows or prevent fraud may be adversely affected. As a result, investors could lose confidence in our financial reporting, which could impact our businesses and the trading price of our securities.

Effective internal controls are necessary for us to provide reliable financial reports, effectively prevent fraud and operate successfully as a public company. If our efforts to maintain internal controls are not successful, we are unable to maintain adequate controls over our financial reporting and processes in the future or we are unable to comply 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 securities.

Our businesses may be adversely affected by the intentional misconduct of our employees.

We are committed to living our core values of safety, integrity, accountability, initiative and respect and complying with all applicable laws and regulations. Despite that commitment and our efforts to prevent misconduct, it is possible for employees to engage in intentional misconduct, fail to uphold our core values, and violate laws and regulations for individual gain through contract or procurement fraud, misappropriation, bribery or corruption, fraudulent related-party transactions and serious breaches of

CenterPoint Energy's Ethics and Compliance Code and Standards of Conduct/Business Ethics policy, among other policies. If such intentional misconduct by employees should occur, it could result in substantial liability, higher costs, increased regulatory scrutiny and negative public perceptions.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

Character of Ownership

We own our principal properties in fee. Most of our natural gas mains are located, pursuant to easements and other rights, on public roads or on land owned by others.

Natural Gas Distribution

For information regarding the properties of our Natural Gas Distribution business segment, please read "Business — Our Business — Natural Gas Distribution — Assets" in Item 1 of this report, which information is incorporated herein by reference.

Energy Services

For information regarding the properties of our Energy Services business segment, please read "Business — Our Business — Energy Services — Assets" in Item 1 of this report, which information is incorporated herein by reference.

Midstream Investments

For information regarding the properties of our Midstream Investments business segment, please read "Business — Our Business — Midstream Investments" in Item 1 of this report, which information is incorporated herein by reference.

Item 3. ***Legal Proceedings***

For a discussion of material legal and regulatory proceedings affecting us, please read "Business — Regulation" and "Business — Environmental Matters" in Item 1 of this report, "Management's Narrative Analysis of Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of this report and Note 14(d) to our consolidated financial statements, which information is incorporated herein by reference.

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***

All of the 1,000 outstanding shares of CERC Corp.'s common stock are held by Utility Holding, LLC, a wholly-owned subsidiary of CenterPoint Energy.

We paid dividends of $643 million, $43 million and $405 million to our parent in 2016, 2015 and 2014, respectively.

Our revolving credit facility limits our debt as a percentage of total capitalization to 65%. This covenant could restrict our ability to distribute dividends.

Item 6. ***Selected Financial Data***

The information called for by Item 6 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly-Owned Subsidiaries).

Item 7. ***Management's Narrative Analysis of Results of Operations***

The following narrative analysis should be read in combination with our consolidated financial statements and notes contained in Item 8 of this report.

Background

We are an indirect, wholly-owned subsidiary of CenterPoint Energy, a public utility holding company. Our operating subsidiaries own and operate natural gas distribution facilities, supply natural gas to commercial and industrial customers and electric and natural gas utilities and own interests in Enable as described below. Our operating subsidiaries include:

- NGD, which owns and operates natural gas distribution systems in six states; and

- CES, which obtains and offers competitive variable and fixed-price physical natural gas supplies and services primarily to commercial and industrial customers and electric and natural gas utilities in 31 states.

As of December 31, 2016, we also owned approximately 54.1% of the limited partner interests in Enable, an unconsolidated partnership jointly controlled with OGE, which owns, operates and develops natural gas and crude oil infrastructure assets.

Business Segments

In this section, we discuss our results on a consolidated basis and individually for each of our business segments. We also discuss our liquidity, capital resources and critical accounting policies. We are first and foremost an energy delivery company and it is our intention to remain focused on these segments of the energy business. The results of our business operations are significantly impacted by weather, customer growth, economic conditions, cost management, competition, rate proceedings before regulatory agencies and other actions of the various regulatory agencies to whose jurisdiction we are subject. Our natural gas distribution services are also subject to rate regulation and are reported in the Natural Gas Distribution business segment. For further information about our Natural Gas Distribution business segment, see "Business — Our Business — Natural Gas Distribution" in Item 1 of Part I of this report. Our Energy Services business segment includes non-rate regulated natural gas sales to, and transportation and storage services, for commercial and industrial customers. For further information about our Energy Services business segment, see "Business — Our Business — Energy Services" in Item 1 of Part I of this report. The results of our Midstream Investments business segment are dependent upon the results of Enable, which are driven primarily by the volume of natural gas, NGLs and crude oil that Enable gathers, processes and transports across its systems and other factors as discussed below under "— Factors Influencing Our Midstream Investments Segment." Our Other Operations business segment includes unallocated corporate costs and inter-segment eliminations.

EXECUTIVE SUMMARY

Factors Influencing Our Businesses and Industry Trends

We expect our and Enable's businesses to continue to be affected by the key factors and 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.

We are an energy delivery company. The majority of our revenues are generated from the sale of natural gas by our subsidiaries. To assess our financial performance, our management primarily monitors operating income and cash flows from our business segments. Within these broader financial measures, we monitor margins, operation and maintenance expense, interest expense, capital spending and working capital requirements. In addition to these financial measures we also monitor a number of variables that management considers important to the operation of our business segments, including the number of customers, throughput, use per customer, commodity prices and heating degree days. We also monitor system reliability, safety factors and customer satisfaction to gauge our performance.

To the extent adverse economic conditions affect our suppliers and customers, results from our energy delivery businesses may suffer. For example, we conduct business in Houston, Texas, where a higher percentage of employment is tied to the energy sector relative to other regions of the country. Although Houston, Texas has a diverse economy, employment in the energy industry remains important. To the extent population growth is affected by lower energy prices and there is financial pressure on some of our customers who operate within the energy industry, there may be an impact on the growth rate of our customer base and overall demand. Given the significant decline in energy and commodity prices in 2015, the rate of growth in employment in Houston, which had been greater than the national average, has declined and is now more in line with the national average. We expect this trend to continue in the foreseeable future. Also, adverse economic conditions, coupled with concerns for protecting the environment, may cause consumers to use less energy or avoid expansions of their facilities, resulting in less demand for our services.

Performance of our Natural Gas Distribution business segment is significantly influenced by the number of customers and energy usage per customer. Weather conditions can have a significant impact on energy usage, and we compare our results on a weather adjusted basis. In 2016, our Houston service area experienced above normal warmth with episodes of flooding. Houston's average temperature of 71.4 degrees Fahrenheit was the seventh highest (record 2012) going back to 1889. In 2015, our Houston service area experienced some of the mildest temperatures on record during November and December. Every state in which we distribute natural gas had a warmer than normal winter in 2016 and 2015. NGD has utilized weather hedges in the past to help reduce the impact of mild weather on its financial results. However, NGD did not enter a weather hedge for the last two winter seasons as a result of NGD's Minnesota division implementing a full decoupling pilot in July 2015. We also have various rate mechanisms in place that help to mitigate the impact of abnormal weather on our financial results. Our long-term national trends indicate customers have reduced their energy consumption, and reduced consumption can adversely affect our results. However, due to more affordable energy prices and continued economic improvement in the areas we serve, the trend toward lower usage has slowed in some of the areas we serve. In Minnesota and Arkansas, rate adjustment mechanisms counter the impact of declining usage from energy efficiency improvements. In addition, in many of our service areas, particularly in the Houston area and Minnesota, we have benefited from growth in the number of customers. This growth also tends to mitigate the effects of reduced consumption. We anticipate that this trend will continue as the regions' economies continue to grow. The profitability of our businesses is influenced significantly by the regulatory treatment we receive from the various state and local regulators who set NGD's rates.

Our Energy Services business segment contracts with customers for transportation, storage and sales of natural gas on an unregulated basis. Its operations serve customers primarily in the central United States. The segment benefits from favorable price differentials, either on a geographic basis or on a seasonal basis. While this business utilizes financial derivatives to mitigate the effects of price movements, it does not enter into risk management contracts for speculative purposes and maintains a low VaR to avoid significant financial exposures. In 2016, CES acquired Continuum, which included approximately 13,000 customers and 175 Bcf of gas sales. The customer base was comprised of a mix similar to our existing business. This acquisition helped drive the overall operating income increase for Energy Services in 2016 as compared to 2015, excluding mark-to-market accounting for derivatives. In 2015 and 2014, Energy Services exhibited strong commercial and industrial customer results while capitalizing on asset optimization opportunities created by basis volatility. Extreme cold weather in 2014 also increased throughput and margin from our weather sensitive customers. In January 2017, CES acquired AEM. For more information regarding this acquisition, see Note 17 to our consolidated financial statements.

The nature of our businesses requires significant amounts of capital investment, and we rely on internally generated cash, borrowings under our credit facilities, proceeds from commercial paper and issuances of debt and equity in the capital markets to satisfy these capital needs. We strive to maintain investment grade ratings for our securities to access the capital markets on terms we consider reasonable. A reduction in our ratings generally would increase our borrowing costs for new issuances of debt, as well as borrowing costs under our existing revolving credit facilities, and may prevent us from accessing the commercial paper markets. Disruptions in the financial markets can also affect the availability of new capital on terms we consider attractive. In those circumstances, companies like us may not be able to obtain certain types of external financing or may be required to accept terms less favorable than they would otherwise accept. For that reason, we seek to maintain adequate liquidity for our businesses through existing credit facilities and prudent refinancing of existing debt.

The regulation of natural gas pipelines and related facilities by federal and state regulatory agencies affects our business. In accordance with natural gas pipeline safety and integrity regulations, we are making, and will continue to make, significant capital investments in our service territories, which are necessary to help operate and maintain a safe, reliable and growing natural gas system. Our compliance expenses may also increase as a result of preventative measures required under these regulations. Consequently, new rates in the areas we serve are necessary to recover these increasing costs.

Consistent with the regulatory treatment of such costs, we can defer the amount of pension expense that differs from the level of pension expense included in our base rates for our Natural Gas Distribution business segment in Texas.

Factors Influencing Our Midstream Investments Segment

The results of our Midstream Investments segment are dependent upon the results of Enable, which are driven primarily by the volume of natural gas, NGLs and crude oil that Enable gathers, processes and transports across its systems. These volumes depend significantly on the level of production from natural gas wells connected to Enable's systems across a number of U.S. mid-continent markets. Aggregate production volumes are affected by the overall amount of oil and gas drilling and completion activities. Production must be maintained or increased by new drilling or other activity, because the production rate of oil and gas wells declines over time.

Enable expects its business to continue to be impacted by the trends affecting the midstream industry, discussed below. Enable's outlook is based on its management's assumptions regarding the impact of these trends that it has developed by interpreting the information currently available to them. If Enable management's assumptions or interpretation of available information prove to be incorrect, Enable's future financial condition and results of operations may differ materially from its expectations.

Enable's business is impacted by commodity prices, which have declined and otherwise experienced significant volatility in recent years. In early 2016, natural gas and crude oil prices dropped to their lowest levels in over 10 years. Both natural gas and crude oil prices increased moderately in the second half of 2016. If current commodity prices levels persist, or if commodity price levels decline, Enable's future volumes and cash flows may be negatively impacted. Commodity prices impact the drilling and production of natural gas and crude oil in the areas served by Enable's systems, and the volumes on Enable's systems are negatively impacted if producers decrease drilling and production in those areas served. Both Enable's gathering and processing segment and its transportation and storage segment can be impacted by drilling and production. Enable's gathering and processing segment primarily serves producers, and many producers utilize the services provided by its transportation and storage segment. A decrease in volumes will decrease cash flows from Enable's systems. In addition, Enable's processing arrangements expose it to commodity price fluctuations. Enable has attempted to mitigate the impact of commodity prices on its business by entering into hedges, focusing on contracting fee-based business and converting existing commodity-based contracts to fee-based contracts.

Despite recent low commodity prices, Enable's long-term view is that natural gas and crude oil production in the U.S. will increase. 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. Advancements in technology have allowed producers to efficiently extract natural gas and crude oil from these formations and plays. As a result, the proven reserves of natural gas and crude oil in the U.S. have significantly increased and the price of natural gas and crude oil has decreased compared to historical periods.

Natural gas continues to be a critical component of energy demand in the U.S. Over the long term, Enable's 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 power plants by natural gas-fired power plants due to the price of natural gas and stricter government environmental regulations on the mining and burning of coal. The EIA projects that the majority of domestic consumption growth will be in the electric power, industrial and liquefaction for export sectors where the aggregate natural gas demand of these sectors is expected to grow from approximately 17.8 trillion cubic feet of natural gas in 2016 to approximately 21.0 trillion cubic feet of natural in 2040. Enable's management believes that increasing consumption of natural gas over the long term in these sectors will continue to drive demand for Enable's natural gas gathering, processing, transportation and storage services.

Enable may access the capital markets to fund its expansion capital expenditures. Historically, unit prices of midstream master limited partnerships have experienced periods of volatility. In addition, because Enable's common units are yield-based securities, rising market interest rates could impact the relative attractiveness of Enable's common units to investors. Further, fluctuations in energy and commodity prices can create volatility in Enable's common unit prices, which could impact investor appetite for its common units. Volatility in energy and commodity prices, as well as other macro-economic factors could impact the relative attractiveness of Enable's debt securities to investors. As a result of capital market volatility, Enable may be unable to issue equity securities or debt on satisfactory terms, or at all, which may limit its ability to expand its operations or make future acquisitions.

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 Enable's business. For example, the DOT's PHMSA has established pipeline integrity management programs that require more frequent inspections of pipeline facilities and other preventative measures, which may increase Enable's 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 Enable's gathering systems.

Enable relies on certain key natural gas producer customers for a significant portion of its natural gas and NGLs supply. For the year ended December 31, 2016, Enable's top ten natural gas producer customers accounted for approximately 66% of its gathered volumes. These customers include affiliates of Continental, Vine, GeoSouthern, XTO Energy, Apache, Tapstone, Chesapeake, BP Energy Company, Covey Park and Marathon. Further, Enable relies on certain key utilities and producers for a significant portion of its transportation and storage demand. For the year ended December 31, 2016, Enable's top transportation and storage customers by revenue were affiliates of CenterPoint Energy, Spire, XTO Energy, American Electric Power Company, OGE, Continental, Chesapeake, Midcoast Energy Partners, EOG Resources and Entergy.

Enable is exposed to certain credit risks relating to its ongoing business operations. Credit risk includes the risk that counterparties that owe Enable money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, Enable may be forced to enter into alternative arrangements. In that event, Enable's financial results could be adversely affected, and Enable could incur losses. Enable examines the creditworthiness of third-party customers to whom it extends credit and manages its exposure to credit risk through credit analysis, credit approval, credit limits and monitoring procedures, and for certain transactions, Enable may request letters of credit, prepayments or guarantees or seek to renegotiate its contract to reduce credit exposure.

Significant Events

Regulatory Proceedings. For details related to our pending and completed regulatory proceedings in 2016, see "—Liquidity and Capital Resources — Regulatory Matters" below.

Debt Repayments. In 2016, we retired approximately $325 million aggregate principal of senior notes. For further information about our debt transactions, see Note 12 to our consolidated financial statements.

Continuum Acquisition. In April 2016, CES closed the previously announced agreement to acquire the energy services business of Continuum. For more information regarding the acquisition, see Note 4 to our consolidated financial statements.

AEM Acquisition. In January 2017, CES closed the previously announced agreement to acquire AEM. For more information regarding this acquisition, see Note 17 to our consolidated financial statements.

CERTAIN FACTORS AFFECTING FUTURE EARNINGS

Our past earnings and results of operations are not necessarily indicative of our future earnings and results of operations. The magnitude of our and Enable's future earnings and results of our and Enable's operations will depend on or be affected by numerous factors including:

- the performance of Enable, the amount of cash distributions we receive from Enable, and the value of our interest in Enable, and factors that may have a material impact on such performance, cash distributions and value, including factors such as:
    - competitive conditions in the midstream industry, and actions taken by Enable's customers and competitors, including the extent and timing of the entry of additional competition in the markets served by Enable;
    - the timing and extent of changes in the supply of natural gas and associated commodity prices, particularly prices of natural gas and NGLs, the competitive effects of the available pipeline capacity in the regions served by Enable, and the effects of geographic and seasonal commodity price differentials, including the effects of these circumstances on re-contracting available capacity on Enable's interstate pipelines;
    - the demand for crude oil, natural gas, NGLs and transportation and storage services;
    - environmental and other governmental regulations, including the availability of drilling permits and the regulation of hydraulic fracturing;
    - recording of non-cash goodwill, long-lived asset or other than temporary impairment charges by or related to Enable;
    - changes in tax status;
    - access to debt and equity capital; and
    - the availability and prices of raw materials and services for current and future construction projects;
- industrial, commercial and residential growth in our service territories and changes in market demand, including the effects of energy efficiency measures and demographic patterns;
- timely and appropriate rate actions that allow recovery of costs and a reasonable return on investment;
- future economic conditions in regional and national markets and their effect on sales, prices and costs;
- weather variations and other natural phenomena, including the impact of severe weather events on operations and capital;

- state and federal legislative and regulatory actions or developments affecting various aspects of our businesses (including the businesses of Enable), including, among others, energy deregulation or re-regulation, pipeline integrity and safety, changes in regulation and legislation pertaining to trade, health care, finance and actions regarding the rates charged by our regulated businesses;
- tax reform and legislation;
- our ability to mitigate weather impacts through normalization or rate mechanisms, and the effectiveness of such mechanisms;
- the timing and extent of changes in commodity prices, particularly natural gas, and the effects of geographic and seasonal commodity price differentials;
- problems with regulatory approval, construction, implementation of necessary technology or other issues with respect to major capital projects that result in delays or in cost overruns that cannot be recouped in rates;
- local, state and federal legislative and regulatory actions or developments relating to the environment, including those related to global climate change;
- the impact of unplanned facility outages;
- any direct or indirect effects on our facilities, operations and financial condition resulting from terrorism, cyber-attacks, data security breaches or other attempts to disrupt our businesses or the businesses of third parties, or other catastrophic events such as fires, earthquakes, explosions, leaks, floods, droughts, hurricanes, pandemic health events or other occurrences;
- our ability to invest planned capital and the timely recovery of our investment in capital;
- our ability to control operation and maintenance costs;
- actions by credit rating agencies;
- the sufficiency of our insurance coverage, including availability, cost, coverage and terms;
- the investment performance of CenterPoint Energy, Inc.'s pension and postretirement benefit plans;
- commercial bank and financial market conditions, our access to capital, the cost of such capital, and the results of our financing and refinancing efforts, including availability of funds in the debt capital markets;
- changes in interest rates or rates of inflation;
- inability of various counterparties to meet their obligations to us;
- non-payment for our services due to financial distress of our customers;
- effectiveness of our risk management activities;
- our potential business strategies and strategic initiatives, including restructurings, joint ventures and acquisitions or dispositions of assets or businesses, which we cannot assure you will be completed or will have the anticipated benefits to us;
- acquisition and merger activities involving us or our competitors;
- our or Enable's ability to recruit, effectively transition and retain management and key employees and maintain good labor relations;
- the ability of GenOn (formerly known as RRI Energy, Inc., Reliant Energy and RRI), a wholly-owned subsidiary of NRG, and its subsidiaries to satisfy their obligations to us, including indemnity obligations;
- the outcome of litigation;
- the timing and outcome of any audits, disputes and other proceedings related to taxes;

- the effect of changes in and application of accounting standards and pronouncements; and
- other factors we discuss under “Risk Factors” in Item 1A of this report and in other reports we file from time to time with the SEC.

CONSOLIDATED RESULTS OF OPERATIONS

Our results of operations are affected by seasonal fluctuations in the demand for natural gas and price movements of energy commodities as well as natural gas basis differentials. Our results of operations are also affected by, among other things, the actions of various federal and state governmental authorities having jurisdiction over rates we charge, competition in our various business operations, debt service costs and income tax expense.

The following table sets forth selected financial data for the years ended December 31, 2016, 2015 and 2014, followed by a discussion of our consolidated results of operations based on operating income. We have provided a reconciliation of consolidated operating income to net income below.

	Year Ended December 31,		
	2016	2015	2014
	(in millions)		
Revenues	$ 4,454	$ 4,527	$ 6,367
Expenses:			
Natural gas	2,966	3,102	4,921
Operation and maintenance	777	741	751
Depreciation and amortization	249	227	206
Taxes other than income taxes	144	144	154
Total	4,136	4,214	6,032
Operating Income	318	313	335
Interest and other finance charges	(122)	(137)	(141)
Equity in earnings (losses) of unconsolidated affiliates	208	(1,633)	308
Other income, net	3	6	9
Income (Loss) Before Income Taxes	407	(1,451)	511
Income Tax Expense (Benefit)	162	(539)	188
Net Income (Loss)	$ 245	$ (912)	$ 323

2016 Compared to 2015

Net Income. We reported net income of $245 million for 2016 compared to a net loss of $912 million for 2015.

The increase in net income of $1,157 million was due to the following key factors:

- a $1,841 million increase in equity earnings from our investment in Enable, as 2015 results included impairment charges of $1,846 million, discussed further in Note 11 to our consolidated financial statements;
- a $15 million decrease in interest expense due to lower weighted average interest rates on outstanding debt; and
- a $5 million increase in operating income discussed below by segment.

These increases were partially offset by:

- a $701 million increase in income tax expense due to higher income before tax; and
- $3 million decrease in interest income included in Other income, net shown above.

Income Tax Expense. We reported an effective tax rate of 40% and 37% for the years ended December 31, 2016 and 2015, respectively. The higher effective tax rate of 40% is due to a Louisiana state tax law change in the second quarter of 2016 resulting in an increase to CERC’s deferred tax liability.

2015 Compared to 2014

Net Income. We reported a net loss of $912 million for 2015 compared to net income of $323 million for 2014.

The decrease in net income of $1,235 million was due to the following key factors:

- a $1,941 million decrease in equity earnings of unconsolidated affiliates, which included impairment charges of $1,846 million, discussed further in Note 11 to our consolidated financial statements;

- a $22 million decrease in operating income discussed below by segment; and

- a $3 million decrease in Other Income, net shown above.

These decreases were partially offset by:

- a $727 million decrease in income tax expense; and

- a $4 million decrease in interest expense.

Income Tax Expense. We reported an effective tax rate of 37% for each of the years ended December 31, 2015 and 2014.

RESULTS OF OPERATIONS BY BUSINESS SEGMENT

The following table presents operating income (loss) for each of our business segments for 2016, 2015 and 2014. Included in revenues are intersegment sales. We account for intersegment sales as if the sales were to third parties, that is, at current market prices.

Operating Income (Loss) by Business Segment

	Year Ended December 31,		
	2016	2015	2014
	(in millions)		
Natural Gas Distribution	$ 303	$ 273	$ 287
Energy Services	20	42	52
Other Operations	(5)	(2)	(4)
Total Consolidated Operating Income	$ 318	$ 313	$ 335

Natural Gas Distribution

The following table provides summary data of our Natural Gas Distribution business segment for 2016, 2015 and 2014:

	Year Ended December 31,		
	2016	2015	2014
	(in millions, except throughput and customer data)		
Revenues	$ 2,409	$ 2,632	$ 3,301
Expenses:			
Natural gas	1,008	1,297	1,961
Operation and maintenance	714	697	700
Depreciation and amortization	242	222	201
Taxes other than income taxes	142	143	152
Total expenses	2,106	2,359	3,014
Operating Income	$ 303	$ 273	$ 287
Throughput (in Bcf):			
Residential	152	171	197
Commercial and industrial	259	262	270
Total Throughput	411	433	467
Number of customers at end of period:			
Residential	3,183,538	3,149,845	3,124,542
Commercial and industrial	255,806	253,921	249,272
Total	3,439,344	3,403,766	3,373,814

2016 Compared to 2015. Our Natural Gas Distribution business segment reported operating income of $303 million for 2016 compared to $273 million for 2015.

Operating income increased $30 million primarily as a result of the following key factors:

- rate increases of $55 million, primarily from the 2015 Minnesota rate case, including the decoupling rider, and the Texas GRIP filing;
- lower bad debt expense of $12 million resulting from lower customer bills due to warmer than normal weather as well as credit and collections process improvements that have reduced write-offs;
- an increase of $26 million from weather normalization adjustments, including weather-related decoupling and hedging activities, partially offset by $19 million of milder weather effects; and
- customer growth of $5 million from the addition of over 35,000 new customers.

These increases were partially offset by:

- increased depreciation and amortization of $20 million, primarily due to ongoing additions to plant in service;
- higher labor and benefits expenses of $11 million, primarily driven by increased pension costs;
- higher contract services expenses of $10 million, primarily for increased pipeline integrity, leak surveying and repair activities; and
- increased operations and maintenance expenses of $8 million related to higher support services costs and other miscellaneous expenses.

Increased expense related to energy efficiency programs of $1 million and decreased expense related to gross receipt taxes of $3 million were offset by a corresponding increase/decrease in the related revenues.

2015 Compared to 2014. Our Natural Gas Distribution business segment reported operating income of $273 million for 2015 compared to $287 million for 2014.

Operating income decreased $14 million primarily as a result of the following key factors:

- decreased usage of $25 million as a result of warmer weather compared to the prior year, partially mitigated by weather hedges and weather normalization adjustments;
- higher depreciation and amortization of $22 million; and
- increase in taxes of $2 million.

These decreases were partially offset by:

- rate increases of $23 million;
- increased economic activity across our footprint of $7 million, including the addition of approximately 30,000 customers; and
- increased other revenue of $5 million.

Decreased expense related to energy efficiency programs of $4 million and decreased expense related to gross receipt taxes of $10 million were offset by a corresponding decrease in the related revenues.

Energy Services

The following table provides summary data of our Energy Services business segment for 2016, 2015 and 2014:

	Year Ended December 31,		
	2016	2015	2014
	(in millions, except throughput and customer data)		
Revenues	$ 2,099	$ 1,957	$ 3,179
Expenses:			
Natural gas	2,011	1,867	3,073
Operation and maintenance	59	42	47
Depreciation and amortization	7	5	5
Taxes other than income taxes	2	1	2
Total expenses	2,079	1,915	3,127
Operating Income	$ 20	$ 42	$ 52
Mark-to-market gain (loss)	$ (21)	$ 4	$ 29
Throughput (in Bcf)	777	618	631
Number of customers at end of period (1)	30,332	18,099	17,964

(1) These numbers do not include approximately 60,100 and 9,700 natural gas customers as of December 31, 2016 and 2014, respectively, that are under residential and small commercial choice programs invoiced by their host utility.

2016 Compared to 2015. Our Energy Services business segment reported operating income of $20 million for 2016 compared to $42 million for 2015. The decrease in operating income of $22 million was due to a $25 million decrease from mark-to-market accounting for derivatives associated with certain natural gas purchases and sales used to lock in economic margins. Partially offsetting this decrease was an increase in operating income for 2016 as compared to 2015 attributable to increased throughput and number of customers due to the Continuum acquisition. Operating income in 2016 also included $3 million of operation and maintenance expenses and $3 million of amortization expenses specifically related to the acquisition and integration of Continuum.

2015 Compared to 2014. Our Energy Services business segment reported operating income of $42 million for 2015 compared to $52 million for 2014. The decrease in operating income of $10 million was due to a $25 million decrease from mark-to-market accounting for derivatives associated with certain natural gas purchases and sales used to lock in economic margins. Offsetting this decrease was a $5 million reduction in operation and maintenance expenses and a $4 million benefit related to a lower inventory write down in 2015. The remaining increase in operating income was primarily due to improved margins resulting from reduced fixed costs.

Midstream Investments

The following table summarizes the equity earnings (losses) of our Midstream Investments business segment for 2016, 2015 and 2014:

	Year Ended December 31,		
	2016	2015 (2)	2014 (3)
	(in millions)		
Enable (1)	$ 208	$ (1,633)	$ 303
SESH	—	—	5
Total	$ 208	$ (1,633)	$ 308

(1) These amounts include impairment charges totaling $1,846 million composed of the impairment of our investment in Enable of $1,225 million and our share, $621 million, of impairment charges Enable recorded for goodwill and long-lived assets for the year ended December 31, 2015. This impairment is offset by $213 million of earnings for the year ended December 31, 2015.

(2) We contributed our remaining 0.1% interest in SESH to Enable on June 30, 2015.

(3) On April 16, 2014, Enable completed its initial public offering and, as a result, our limited partner interest in Enable was reduced from approximately 58.3% to approximately 54.7%. On May 30, 2014, we contributed to Enable our 24.95% interest in SESH, which increased our limited partner interest in Enable from approximately 54.7% to approximately 55.4% and reduced our interest in SESH to 0.1%.

Fluctuations in Commodity Prices and Derivative Instruments

For information regarding our exposure to risk as a result of fluctuations in commodity prices and derivative instruments, please read "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this report.

LIQUIDITY AND CAPITAL RESOURCES

Our liquidity and capital requirements are affected primarily by our results of operations, capital expenditures, debt service requirements, tax payments, working capital needs and various regulatory actions. Our principal anticipated cash requirements for 2017 include the following:

- capital expenditures of approximately $544 million;
- maturing senior notes of $250 million; and
- acquisition of AEM for approximately $140 million, including estimated working capital of $100 million.

We expect that anticipated 2017 cash needs will be met with borrowings under our credit facility, proceeds from commercial paper, anticipated cash flows from operations and distributions from Enable. Discretionary financing or refinancing may result in the issuance of debt securities in the capital markets or the arrangement of additional credit facilities. Issuances of debt in the capital markets, funds raised in the commercial paper markets and additional credit facilities may not, however, be available to us on acceptable terms.

The following table sets forth our actual capital expenditures for 2016 and estimates of our capital expenditures for currently planned projects for 2017 through 2021:

	2016	2017	2018	2019	2020	2021
			(in millions)			
Natural Gas Distribution	$ 510	$ 534	$ 534	$ 534	$ 534	$ 534
Energy Services	5	10	10	10	10	10
Total	$ 515	$ 544	$ 544	$ 544	$ 544	$ 544

Our capital expenditures are expected to be used for investment in infrastructure for our natural gas distribution operations. These capital expenditures are anticipated to maintain reliability and safety as well as expand our systems through value-added projects.

The following table sets forth estimates of our contractual obligations, including payments due by period (in millions):

Contractual Obligations	Total	2017	2018-2019	2020-2021	2022 and thereafter
			(in millions)		
Long-term debt	$ 2,375	$ 250	$ 300	$ 1,162	$ 663
Interest payments — long-term debt (1)	1,157	109	161	134	753
Short-term borrowings	35	35	—	—	—
Operating leases (2)	25	5	8	5	7
Benefit obligations (3)	—	—	—	—	—
Non-trading derivative liabilities	46	41	5	—	—
Other commodity commitments (4)	1,456	461	735	252	8
Total contractual cash obligations (5)	$ 5,094	$ 901	$ 1,209	$ 1,553	$ 1,431

(1) We calculated estimated interest payments for long-term debt as follows: for fixed-rate debt and term debt, we calculated interest based on the applicable rates and payment dates; for variable-rate debt and/or non-term debt, we used interest rates in place as of December 31, 2016. We typically expect to settle such interest payments with cash flows from operations and short-term borrowings.

(2) For a discussion of operating leases, please read Note 14(c) to our consolidated financial statements.

(3) We expect to contribute approximately $5 million to our postretirement benefits plan in 2017 to fund a portion of our obligations in accordance with rate orders or to fund pay-as-you-go costs associated with the plan.

(4) For a discussion of other commodity commitments, please read Note 14(a) to our consolidated financial statements.

(5) This table does not include estimated future payments for expected future AROs. These payments are primarily estimated to be incurred after 2022. We record a separate liability for the fair value of AROs which totaled $169 million as of December 31, 2016. See Note 3(c) to our consolidated financial statements.

Off-Balance Sheet Arrangements

Other than operating leases, we have no off-balance sheet arrangements.

Regulatory Matters

Rate Change Applications

We are routinely involved in rate change applications before state regulatory authorities. Those applications include general rate cases, where the entire cost of service of the utility is assessed and reset. We are periodically involved in proceedings to adjust our capital tracking mechanisms in Texas (GRIP), our cost of service adjustments in Arkansas, Louisiana, Mississippi, and Oklahoma (FRP, RSP, RRA and PBRC), our decoupling mechanism in Minnesota, and our energy efficiency cost trackers in Arkansas, Minnesota, Mississippi and Oklahoma (EECR, CIP, EECR and EECR). The table below reflects significant applications pending or completed during 2016.

Mechanism	Annual Increase (in millions)	Filing Date	Effective Date	Approval Date	Additional Information
			Houston, South Texas, Beaumont/East Texas, Texas Coast (Railroad Commission)		
GRIP	18.2	March 2016	July 2016	July 2016	Based on net change in invested capital of $115.5 million.
			Houston and Texas Coast (Railroad Commission) (1)		
Rate Case	31.0	November 2016	(2)	(2)	Based on rate base of $669 million and a 10.25% ROE on a 55.1% equity ratio. Final order is expected in Q2 2017.
			Arkansas (APSC)		
Rate Case	14.2	November 2015	September 2016	September 2016	Based on an ROE of 9.5%. Also approved a FRP.
EECR (3)	0.5	August 2016	January 2017	(2)	Recovers $11.0 million, including an incentive of $0.5 million based on 2015 program performance.
			Mississippi (MPSC)		
RRA	2.7	July 2016	October 2016	October 2016	Based on ROE of 9.47%.
			Minnesota (MPUC)		
Rate Case	27.5	August 2015	December 2016	June 2016	Interim increase of $47.8 million effective in October 2015. Final rates based on an ROE of 9.49% and interim rate refund implemented in December 2016.
CIP (3)	12.7	May 2016	September 2016	September 2016	Based on 2015 results.
Decoupling (4)	24.6	September 2016	September 2016	December 2016	Reflects revenue under recovery for the period July 1, 2015 through June 30, 2016.
			Louisiana (LPSC)		
RSP	1.3	September 2016	December 2016	(2)	Authorized ROE of 9.95% and a capital structure of 48% debt and 52% equity.
RSP	2.3	October 2015	December 2016	(2)	Authorized ROE of 9.95% and a capital structure of 48% debt and 52% equity.
			Oklahoma (OCC)		
EECR (3)	0.4	March 2016	July 2016	July 2016	Recovers $2.4 million, including an incentive of $0.4 million based on 2015 program performance.

(1) In addition to requesting the change in rates, NGD proposed consolidation of the Houston and Texas Coast divisions into a Texas Gulf division.

(2) Effective dates or approval dates not yet available, and approved rates could differ materially.

(3) Amounts are recorded when approved.

(4) The amount was recorded during the under recovery period.

Other Matters

Credit Facility

On March 4, 2016, we announced that we had refinanced our existing $600 revolving credit facility, which would have expired in 2019, with new a $600 million five-year senior unsecured revolving credit facility. The revolving credit facility may be drawn on from time to time to provide funds used for general corporate purposes and may also be utilized to obtain letters of credit. Our revolving credit facility backstops our commercial paper program.

As of February 10, 2017, we had the following revolving credit facility:

Execution Date	Size of Facility		Amount Utilized at February 10, 2017 (1)		Termination Date
		(in millions)			
March 3, 2016	$	600	$	591	March 3, 2021

(1) Represents outstanding commercial paper of $587 million and outstanding letters of credit of $4 million.

For further details related to our revolving credit facility, please see Note 12 to our consolidated financial statements.

Borrowings under the revolving credit facility are subject to customary terms and conditions. However, there is no requirement that we make representations prior to borrowings as to the absence of material adverse changes or litigation that could be expected to have a material adverse effect. Borrowings under the revolving credit facility are subject to acceleration upon the occurrence of events of default that we consider customary. The revolving credit facility also provides for customary fees, including commitment fees, administrative agent fees, fees in respect of letters of credit and other fees. The spread to LIBOR and the commitment fees fluctuate based on our credit rating. We are currently in compliance with the various business and financial covenants in our revolving credit facility.

Long-term Debt

In 2016, we retired $325 million aggregate principal amount of senior notes. For further information about our 2016 debt transactions, see Note 12 to our consolidated financial statements.

Securities Registered with the SEC

On January 31, 2017, we filed a shelf registration statement with the SEC registering an indeterminate principal amount of our senior debt securities. The shelf registration statement will expire on January 31, 2020.

Temporary Investments

As of February 10, 2017, we had no external temporary investments.

Money Pool

We participate in a money pool through which we and certain of our affiliates can borrow or invest on a short-term basis. Funding needs are aggregated and external borrowing or investing is based on the net cash position. The net funding requirements of the money pool are expected to be met with borrowings by CenterPoint Energy under its revolving credit facility or the sale by CenterPoint Energy of its commercial paper. As of February 10, 2017, we had no investment in or borrowings from the money pool. The money pool may not provide sufficient funds to meet our cash needs.

Impact on Liquidity of a Downgrade in Credit Ratings

The interest on borrowings under our credit facility is based on our credit rating. As of February 10, 2017, Moody's, S&P and Fitch had assigned the following credit ratings to our senior unsecured debt:

Moody's		S&P		Fitch	
Rating	Outlook (1)	Rating	Outlook (2)	Rating	Outlook (3)
Baa2	Stable	A-	Developing	BBB	Stable

(1) A Moody's rating outlook is an opinion regarding the likely direction of an issuer's rating over the medium term.

(2) An S&P rating outlook assesses the potential direction of a long-term credit rating over the intermediate to longer term.

(3) A Fitch rating outlook indicates the direction a rating is likely to move over a one- to two-year period.

We cannot assure that the ratings set forth above will remain in effect for any given period of time or that one or more of these ratings will not be lowered or withdrawn entirely by a rating agency. We note that these credit ratings are included for informational purposes and are not recommendations to buy, sell or hold our securities and may be revised or withdrawn at any time by the rating agency. Each rating should be evaluated independently of any other rating. Any future reduction or withdrawal of one or more of our credit ratings could have a material adverse impact on our ability to obtain short- and long-term financing, the cost of such financings and the execution of our commercial strategies.

A decline in credit ratings could increase borrowing costs under our revolving credit facility. If our credit ratings had been downgraded one notch by each of the three principal credit rating agencies from the ratings that existed at December 31, 2016, the impact on the borrowing costs under our credit facility would have been immaterial. A decline in credit ratings would also increase the interest rate on long-term debt to be issued in the capital markets and could negatively impact our ability to complete capital market transactions and to access the commercial paper market. Additionally, a decline in credit ratings could increase cash collateral requirements and reduce earnings of our Natural Gas Distribution and Energy Services business segments.

CES, our wholly-owned subsidiary operating in our Energy Services business segment, provides natural gas sales and services primarily to commercial and industrial customers and electric and natural gas utilities throughout the central and eastern United States. To economically hedge its exposure to natural gas prices, CES uses derivatives with provisions standard for the industry, including those pertaining to credit thresholds. Typically, the credit threshold negotiated with each counterparty defines the amount of unsecured credit that such counterparty will extend to CES. To the extent that the credit exposure that a counterparty has to CES at a particular time does not exceed that credit threshold, CES is not obligated to provide collateral. Mark-to-market exposure in excess of the credit threshold is routinely collateralized by CES. Similarly, mark-to-market exposure offsetting and exceeding the credit threshold may cause the counterparty to provide collateral to CES. As of December 31, 2016, the amount held by CES as collateral aggregated approximately $14 million. Should the credit ratings of CERC Corp. (as the credit support provider for CES) fall below certain levels, CES would be required to provide additional collateral up to the amount of its previously unsecured credit limit. We estimate that as of December 31, 2016, unsecured credit limits extended to CES by counterparties aggregated $367 million, and less than $1 million of such amount was utilized.

Pipeline tariffs and contracts typically provide that if the credit ratings of a shipper or the shipper's guarantor drop below a threshold level, which is generally investment grade ratings from both Moody's and S&P, cash or other collateral may be demanded from the shipper in an amount equal to the sum of three months' charges for pipeline services plus the unrecouped cost of any lateral built for such shipper. If the credit ratings of CERC Corp. decline below the applicable threshold levels, CERC Corp. might need to provide cash or other collateral of as much as $167 million as of December 31, 2016. The amount of collateral will depend on seasonal variations in transportation levels.

Cross Defaults

Under CenterPoint Energy's revolving credit facility, a payment default on, or a non-payment default that permits acceleration of, any indebtedness for borrowed money and certain other specified types of obligations (including guarantees) exceeding $125 million by us will cause a default. A default by CenterPoint Energy would not trigger a default under our debt instruments or revolving credit facility.

Possible Acquisitions, Divestitures and Joint Ventures

From time to time, we consider the acquisition or the disposition of assets or businesses or possible joint ventures, strategic initiatives or other joint ownership arrangements with respect to assets or businesses. Any determination to take action in this regard will be based on market conditions and opportunities existing at the time, and accordingly, the timing, size or success of any efforts and the associated potential capital commitments are unpredictable. We may seek to fund all or part of any such efforts with proceeds from debt issuances. Debt financing may not, however, be available to us at that time due to a variety of events, including, among others, maintenance of our credit ratings, industry conditions, general economic conditions, market conditions and market perceptions.

In February 2016, CenterPoint Energy announced that it was evaluating strategic alternatives for our investment in Enable, including a sale or spin-off qualifying under Section 355 of the U.S. Internal Revenue Code, and CenterPoint Energy continues to evaluate its alternatives, including retaining our investment. There can be no assurances that these evaluations will result in any specific action, and we do not intend to disclose further developments on these initiatives unless and until CenterPoint Energy's board of directors approves a specific action or as otherwise required.

Enable Midstream Partners

We receive quarterly cash distributions from Enable on its common and subordinated units we own. A reduction in the cash distributions we receive from Enable could significantly impact our liquidity. For additional information about cash distributions from Enable, see Notes 11 and 17 to our consolidated financial statements.

Weather Hedge

We have historically entered into partial weather hedges for certain NGD jurisdictions to mitigate the impact of fluctuations from normal weather. We remain exposed to some weather risk as a result of the partial hedges. For more information about our weather hedges, see Note 9(a) to our consolidated financial statements.

Other Factors that Could Affect Cash Requirements

In addition to the above factors, our liquidity and capital resources could be affected by:

- cash collateral requirements that could exist in connection with certain contracts, including our weather hedging arrangements, and gas purchases, gas price and gas storage activities of our Natural Gas Distribution and Energy Services business segments;
- acceleration of payment dates on certain gas supply contracts under certain circumstances, as a result of increased gas prices and concentration of natural gas suppliers;
- increased costs related to the acquisition of natural gas;
- increases in interest expense in connection with debt refinancings and borrowings under credit facilities;
- various legislative or regulatory actions;
- incremental collateral, if any, that may be required due to regulation of derivatives;
- the ability of GenOn and its subsidiaries to satisfy their obligations in respect of GenOn's indemnity obligations to CenterPoint Energy and its subsidiaries;
- slower customer payments and increased write-offs of receivables due to higher gas prices or changing economic conditions;
- the outcome of litigation brought by or against us;
- restoration costs and revenue losses resulting from future natural disasters such as hurricanes and the timing of recovery of such restoration costs; and
- various other risks identified in "Risk Factors" in Item 1A of Part I of this report.

Certain Contractual Limits on Our Ability to Issue Securities and Borrow Money

For information about the total debt to capitalization financial covenants in our revolving credit facility, see Note 12 to our consolidated financial statements.

Relationship with CenterPoint Energy

We are an indirect, wholly-owned subsidiary of CenterPoint Energy. As a result of this relationship, the financial condition and liquidity of our parent company could affect our access to capital, our credit standing and our financial condition.

CRITICAL ACCOUNTING POLICIES

A critical accounting policy is one that is both important to the presentation of our financial condition and results of operations and requires management to make difficult, subjective or complex accounting estimates. An accounting estimate is an approximation made by management of a financial statement element, item or account in the financial statements. Accounting estimates in our historical consolidated financial statements measure the effects of past business transactions or events, or the present status of an asset or liability. The accounting estimates described below require us to make assumptions about matters that are highly uncertain at the time the estimate is made. Additionally, different estimates that we could have used or changes in an accounting estimate that are reasonably likely to occur could have a material impact on the presentation of our financial condition, results of operations or cash flows. The circumstances that make these judgments difficult, subjective and/or complex have to do with the need to make estimates about the effect of matters that are inherently uncertain. Estimates and assumptions about future events and their effects cannot be predicted with certainty. We base our estimates on historical experience and on various other assumptions that we believe to be reasonable under the circumstances, the results of which form the basis for making judgments. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. Our significant accounting policies are discussed in Note 2 to our consolidated financial statements. We believe the following accounting policies involve the application of critical accounting estimates. Accordingly, these accounting estimates have been reviewed and discussed with the audit committee of the board of directors of CenterPoint Energy.

Accounting for Rate Regulation

Accounting guidance for regulated operations provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. Our Natural Gas Distribution business segment applies this accounting guidance. Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet as regulatory assets or liabilities and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and the strength or status of applications for rehearing or state court appeals. If events were to occur that would make the recovery of these assets and liabilities no longer probable, we would be required to write off or write down these regulatory assets and liabilities. As of December 31, 2016, we had recorded regulatory assets of $125 million and regulatory liabilities of $769 million.

Impairment of Long-Lived Assets, Including Identifiable Intangibles, Goodwill and Equity Method Investments

We review the carrying value of our long-lived assets, including identifiable intangibles, goodwill and equity method investments whenever events or changes in circumstances indicate that such carrying values may not be recoverable, and at least annually for goodwill as required by accounting guidance for goodwill and other intangible assets. Unforeseen events and changes in market conditions could have a material effect on the value of long-lived assets, including intangibles, goodwill and equity method investments due to changes in estimates of future cash flows, interest rate and regulatory matters and could result in an impairment charge. A loss in value of an equity method investment is recognized when the decline is deemed to be other than temporary. We recorded no goodwill impairments during 2016, 2015 and 2014. We did not record material impairments to long-lived assets, including intangibles during 2016, 2015 and 2014. We recorded impairments totaling $1,225 million to our equity method investments during 2015 and no impairment during 2016 and 2014. See Notes 10 and 11 to our consolidated financial statements for further discussion of the impairments recorded to our equity method investment in 2015.

We performed our annual goodwill impairment test in the third quarter of 2016 and determined, based on the results of the first step, using the income approach, no impairment charge was required for any reporting unit. Our reporting units approximate our reportable segments.

Fair value is the amount at which the asset could be bought or sold in a current transaction between willing parties and may be estimated using a number of techniques, including quoted market prices or valuations by third parties, present value techniques based on estimates of cash flows, or multiples of earnings or revenue performance measures. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

The determination of fair value requires significant assumptions by management which are subjective and forward-looking in nature. To assist in making these assumptions, we utilized a third-party valuation specialist in both determining and testing key assumptions used in the valuation of each of our reporting units. We based our assumptions on projected financial information that we believe is reasonable; however, actual results may differ materially from those projections. These projected cash flows factor in planned growth initiatives, and for our Natural Gas Distribution reporting unit, the regulatory environment. The fair values of our Natural Gas Distribution and Energy Services reporting units significantly exceeded the carrying values.

Although there was not a goodwill asset impairment in our 2016 annual test, an interim impairment test could be triggered by the following: actual earnings results that are materially lower than expected, significant adverse changes in the operating environment, an increase in the discount rate, changes in other key assumptions which require judgment and are forward looking in nature, or if our market capitalization falls below book value for an extended period of time. No impairment triggers were identified subsequent to our 2016 annual test.

During the year ended December 31, 2015, we determined that an other than temporary decrease in the value of our investment in Enable had occurred. The impairment analysis compared the estimated fair value of our investment in Enable to its carrying value. The fair value of the investment was determined using multiple valuation methodologies under both the market and income approaches.

Key assumptions in the market approach include recent market transactions of comparable companies and EBITDA to total enterprise multiples for comparable companies. Due to volatility of the quoted price of Enable's common units, a volume weighted average price was used under the market approach to best approximate fair value at the measurement date. Key assumptions in the income approach include Enable's forecasted cash distributions, projected cash flows of incentive distribution rights, forecasted growth rate of Enable's cash distributions beyond 2020, and the discount rate used to determine the present value of the estimated future cash flows. A weighing of the different approaches was utilized to determine the estimated fair value of our investment in Enable.

As a result of the analysis, we recorded other than temporary impairments on our equity method investment in Enable of $1,225 million during the year ended December 31, 2015. We based our assumptions on projected financial information that we believe is reasonable; however, actual results may differ materially from those projections. It is reasonably possible that the estimate of the impairment of our equity method investment in Enable will change in the near term due to the following: actual Enable cash distribution is materially lower than expected, significant adverse changes in Enable's operating environment, increase in the discount rate, and changes in other key assumptions which require judgment and are forward looking in nature.

Unbilled Energy Revenues

Revenues related to natural gas sales and services are generally recognized upon delivery to customers. However, the determination of deliveries to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, deliveries to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. Unbilled natural gas sales are estimated based on estimated purchased gas volumes, estimated lost and unaccounted for gas and tariffed rates in effect. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

NEW ACCOUNTING PRONOUNCEMENTS

See Note 2(n) to our consolidated financial statements, incorporated herein by reference, for a discussion of new accounting pronouncements that affect us.

OTHER SIGNIFICANT MATTERS

Pension Plans. As discussed in Note 7(a) to our consolidated financial statements, we participate in CenterPoint Energy's qualified and non-qualified pension plans covering substantially all employees. The expected pension cost for 2017 is $35 million, of which we expect $27 million to impact pre-tax earnings, based on an expected return on plan assets of 6.0% and a discount rate of 4.15% as of December 31, 2016. We recorded pension expense of $37 million for the year ended December 31, 2016. Future changes in plan asset returns, assumed discount rates and various other factors related to the pension plans will impact our future pension expense and liabilities. We cannot predict with certainty what these factors will be in the future.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*

Impact of Changes in Interest Rates and Energy Commodity Prices

We are exposed to various market risks. These risks arise from transactions entered into in the normal course of business and are inherent in our consolidated financial statements. Most of the revenues and income from our business activities are affected by market risks. Categories of market risk include exposure to commodity prices through non-trading activities and interest rates. A description of each market risk is set forth below:

- Interest rate risk primarily results from exposures to changes in the level of borrowings and changes in interest rates.

- Commodity price risk results from exposures to changes in spot prices, forward prices and price volatilities of commodities, such as natural gas, NGLs and other energy commodities.

Management has established comprehensive risk management policies to monitor and manage these market risks.

Interest Rate Risk

As of December 31, 2016, we had outstanding long-term debt that subject us to the risk of loss associated with movements in market interest rates.

Our floating-rate obligations aggregated $569 million and $219 million at December 31, 2016 and 2015, respectively. If the floating interest rates were to increase by 10% from December 31, 2016 rates, our combined interest expense would increase by $1 million annually.

As of December 31, 2016 and 2015, we had outstanding fixed-rate debt aggregating $1.8 billion and $2.2 billion, respectively, in principal amount and having a fair value of $2.0 billion and $2.4 billion, respectively. Because these instruments are fixed-rate, they do not expose us to the risk of loss in earnings due to changes in market interest rates (see Note 12 to our consolidated financial statements). However, the fair value of these instruments would increase by approximately $62 million if interest rates were to decline by 10% from their levels at December 31, 2016. In general, such an increase in fair value would impact earnings and cash flows only if we were to reacquire all or a portion of these instruments in the open market prior to their maturity.

Commodity Price Risk From Non-Trading Activities

We manage these risk exposures through the implementation of our risk management policies and framework. We manage our commodity price risk exposures through the use of derivative financial instruments and derivative commodity instrument contracts. During the normal course of business, we review our hedging strategies and determine the hedging approach we deem appropriate based upon the circumstances of each situation.

Derivative instruments such as futures, forward contracts, swaps and options derive their value from underlying assets, indices, reference rates or a combination of these factors. These derivative instruments include negotiated contracts, which are referred to as over-the-counter derivatives, and instruments that are listed and traded on an exchange.

Derivative transactions are entered into in our non-trading operations to manage and hedge certain exposures, such as exposure to changes in natural gas prices. We believe that the associated market risk of these instruments can best be understood relative to the underlying assets or risk being hedged.

We use derivative instruments as economic hedges to offset the commodity price exposure inherent in our businesses. The stand-alone commodity risk created by these instruments, without regard to the offsetting effect of the underlying exposure these instruments are intended to hedge, is described below. We measure the commodity risk of our non-trading energy derivatives using a sensitivity analysis. The sensitivity analysis performed on our non-trading energy derivatives measures the potential loss in fair value based on a hypothetical 10% movement in energy prices. At December 31, 2016, the recorded fair value of our non-trading energy derivatives was a net asset of $38 million (before collateral), all of which is related to our Energy Services business segment. An increase of 10% in the market prices of energy commodities from their December 31, 2016 levels would have decreased the fair value of our non-trading energy derivatives net asset by $7 million.

The above analysis of the non-trading energy derivatives utilized for commodity price risk management purposes does not include the favorable impact that the same hypothetical price movement would have on our non-derivative physical purchases and sales of natural gas to which the hedges relate. Furthermore, the non-trading energy derivative portfolio is managed to complement the physical transaction portfolio, reducing overall risks within limits. Therefore, the adverse impact to the fair value of the portfolio of non-trading energy derivatives held for hedging purposes associated with the hypothetical changes in commodity prices referenced above is expected to be substantially offset by a favorable impact on the underlying hedged physical transactions.

Item 8. ***Financial Statements and Supplementary Data***

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholder of
CenterPoint Energy Resources Corp.
Houston, Texas

We have audited the accompanying consolidated balance sheets of CenterPoint Energy Resources Corp. and subsidiaries (the “Company”, an indirect wholly owned subsidiary of CenterPoint Energy, Inc.) as of December 31, 2016 and 2015, and the related statements of consolidated income, comprehensive income, stockholder’s equity, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of CenterPoint Energy Resources Corp. and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 28, 2017

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(An Indirect, Wholly-Owned Subsidiary of CenterPoint Energy, Inc.)

STATEMENTS OF CONSOLIDATED INCOME

	Year Ended December 31,		
	2016	2015	2014
		(in millions)	
Revenues:			
Utility revenues	$ 2,380	$ 2,603	$ 3,271
Non-utility revenues	2,074	1,924	3,096
Total	4,454	4,527	6,367
Expenses:			
Utility natural gas	983	1,264	1,878
Non-utility natural gas	1,983	1,838	3,043
Operation and maintenance	777	741	751
Depreciation and amortization	249	227	206
Taxes other than income taxes	144	144	154
Total	4,136	4,214	6,032
Operating Income	318	313	335
Other Income (Expense):			
Interest and other finance charges	(122)	(137)	(141)
Equity in earnings (losses) of unconsolidated affiliates	208	(1,633)	308
Other, net	3	6	9
Total	89	(1,764)	176
Income (Loss) Before Income Taxes	407	(1,451)	511
Income tax expense (benefit)	162	(539)	188
Net Income (Loss)	$ 245	$ (912)	$ 323

See Notes to Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(An Indirect, Wholly-Owned Subsidiary of CenterPoint Energy, Inc.)

STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME

	Year Ended December 31,		
	2016	2015	2014
	(in millions)		
Net income (loss)	$ 245	$ (912)	$ 323
Other comprehensive income (loss), net of tax:			
Adjustment to postretirement and other postemployment plans (net of tax of $4, $6 and $1)	(6)	8	(4)
Other comprehensive income (loss)	(6)	8	(4)
Comprehensive income (loss)	$ 239	$ (904)	$ 319

See Notes to Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(An Indirect, Wholly-Owned Subsidiary of CenterPoint Energy, Inc.)

CONSOLIDATED BALANCE SHEETS

	December 31,	
	2016	2015
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1	$ —
Accounts receivable, less bad debt reserve of $14 million and $19 million, respectively	512	350
Accrued unbilled revenue	229	183
Accounts and notes receivable — affiliated companies	5	8
Material and supplies	47	45
Natural gas inventory	131	168
Non-trading derivative assets	51	89
Prepaid expenses and other current assets	81	61
Total current assets	1,057	904
Property, Plant and Equipment, Net	4,569	4,258
Other Assets:		
Goodwill	862	840
Non-trading derivative assets	19	36
Notes receivable — affiliated companies	—	363
Investment in unconsolidated affiliates	2,505	2,594
Other	206	146
Total other assets	3,592	3,979
Total Assets	$ 9,218	$ 9,141

See Notes to Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(An Indirect, Wholly-Owned Subsidiary of CenterPoint Energy, Inc.)

CONSOLIDATED BALANCE SHEETS, cont.

	December 31,	
	2016	2015
	(in millions)	
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current Liabilities:		
Short-term borrowings	$ 35	$ 40
Current portion of long-term debt	250	325
Accounts payable	471	307
Accounts and notes payable — affiliated companies	40	39
Taxes accrued	73	63
Interest accrued	33	36
Customer deposits	80	80
Non-trading derivative liabilities	41	11
Other	124	158
Total current liabilities	1,147	1,059
Other Liabilities:		
Deferred income taxes, net	1,925	1,774
Non-trading derivative liabilities	5	5
Benefit obligations	104	89
Regulatory liabilities	769	734
Other	221	210
Total other liabilities	3,024	2,812
Long-Term Debt, net	2,125	2,016
Commitments and Contingencies (Note 14)		
Stockholder's Equity:		
Common stock	—	—
Paid-in capital	2,489	2,417
Retained earnings	430	828
Accumulated comprehensive income	3	9
Total stockholder's equity	2,922	3,254
Total Liabilities And Stockholder's Equity	$ 9,218	$ 9,141

See Notes to Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(An Indirect, Wholly-Owned Subsidiary of CenterPoint Energy, Inc.)

STATEMENTS OF CONSOLIDATED CASH FLOWS

	Year Ended December 31,		
	2016	2015	2014
	(in millions)		
Cash Flows from Operating Activities:			
Net income (loss)	$ 245	$ (912)	$ 323
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	249	227	206
Amortization of deferred financing costs	9	9	9
Deferred income taxes	156	(542)	178
Write-down of natural gas inventory	1	4	8
Equity in (earnings) losses of unconsolidated affiliates, net of distributions	(208)	1,779	(2)
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues, net	(122)	347	7
Accounts receivable/payable–affiliated companies	4	9	1
Inventory	34	35	(81)
Taxes receivable	—	—	18
Accounts payable	117	(221)	17
Fuel cost recovery	(72)	43	(41)
Interest and taxes accrued	7	58	(3)
Non-trading derivatives, net	29	(6)	(34)
Margin deposits, net	101	(4)	(79)
Other current assets	(19)	13	8
Other current liabilities	2	(11)	(6)
Other assets	(21)	(6)	(11)
Other liabilities	(2)	(5)	11
Other, net	1	(1)	6
Net cash provided by operating activities	511	816	535
Cash Flows from Investing Activities:			
Capital expenditures	(517)	(606)	(512)
Acquisitions, net of cash acquired	(102)	—	—
Distributions from unconsolidated affiliates in excess of cumulative earnings	297	148	—
Decrease in notes receivable–affiliated companies	363	—	—
Investment in unconsolidated affiliates	—	—	(1)
Other, net	1	6	—
Net cash provided by (used in) investing activities	42	(452)	(513)
Cash Flows from Financing Activities:			
Increase (decrease) in short-term borrowings, net	(5)	(13)	10
Proceeds from (payments of) commercial paper, net	350	(122)	223
Payments of long-term debt	(325)	—	—
Dividends to parent	(643)	(43)	(405)
Contribution from parent	72	—	—
Increase (decrease) in notes payable–affiliated companies	—	(188)	150
Other, net	(1)	—	1
Net cash used in financing activities	(552)	(366)	(21)
Net Increase (Decrease) in Cash and Cash Equivalents	1	(2)	1
Cash and Cash Equivalents at Beginning of the Year	—	2	1
Cash and Cash Equivalents at End of the Year	$ 1	$ —	$ 2
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest, net of capitalized interest	116	125	128
Income taxes (refunds), net	3	6	(1)
Non-cash transactions:			
Accounts payable related to capital expenditures	35	37	37
Exercise of SESH put to Enable	—	1	196

See Notes to Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(An Indirect, Wholly-Owned Subsidiary of CenterPoint Energy, Inc.)

STATEMENTS OF CONSOLIDATED STOCKHOLDER'S EQUITY

	2016		2015		2014	
	Shares	Amount	Shares	Amount	Shares	Amount
	(in millions, except share amounts)					
Common Stock						
Balance, beginning of year	1,000	$ —	1,000	$ —	1,000	$ —
Balance, end of year	1,000	—	1,000	—	1,000	—
Additional Paid-in-Capital						
Balance, beginning of year		2,417		2,417		2,416
Contribution from parent		72		—		—
Other		—		—		1
Balance, end of year		2,489		2,417		2,417
Retained Earnings						
Balance, beginning of year		828		1,783		1,865
Net income (loss)		245		(912)		323
Dividend to parent		(643)		(43)		(405)
Balance, end of year		430		828		1,783
Accumulated Other Comprehensive Income						
Balance, end of year:						
Adjustment to postretirement and other postemployment plans		3		9		1
Total accumulated other comprehensive income, end of year		3		9		1
Total Stockholder's Equity		$ 2,922		$ 3,254		$ 4,201

See Notes to Consolidated Financial Statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Background

CERC Corp. is an indirect, wholly-owned subsidiary of CenterPoint Energy, a public utility holding company. CERC Corp.'s operating subsidiaries own and operate natural gas distribution facilities, supply natural gas to commercial and industrial customers and electric and natural gas utilities and own interests in Enable as described in Note 11. CERC Corp.'s operating subsidiaries include:

- NGD, which owns and operates natural gas distribution systems in six states; and
- CES, which obtains and offers competitive variable and fixed-price physical natural gas supplies and services primarily to commercial and industrial customers and electric and natural gas utilities in 31 states.

As of December 31, 2016, CERC Corp. also owned approximately 54.1% of the limited partner interests in Enable, which owns, operates and develops natural gas and crude oil infrastructure assets.

For a description of CERC's reportable business segments, see Note 16.

(2) Summary of Significant Accounting Policies

(a) Use of Estimates

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

(b) Principles of Consolidation

The accounts of CERC Corp. and its wholly-owned and majority owned subsidiaries are included in CERC's consolidated financial statements. All intercompany transactions and balances are eliminated in consolidation. CERC uses the equity method of accounting for investments in entities in which CERC has an ownership interest between 20% and 50% and exercises significant influence. CERC also uses the equity method for investments in which it has ownership percentages greater than 50%, when it exercises significant influence, does not have control and is not considered the primary beneficiary, if applicable.

In 2013, CenterPoint Energy, OGE and affiliates of ArcLight, formed Enable as a private limited partnership. CenterPoint Energy has the ability to significantly influence the operating and financial policies of, but not solely control, Enable and, accordingly, recorded an equity method investment, at the historical costs of net assets contributed.

Under the equity method, CERC adjusts its investment in Enable each period for contributions made, distributions received, CERC's share of Enable's comprehensive income and amortization of basis differences, as appropriate. CERC evaluates its equity method investments for impairment when events or changes in circumstances indicate there is a loss in value of the investment that is other than a temporary decline.

CERC's investment in Enable is considered to be a VIE because the power to direct the activities that most significantly impact Enable's economic performance does not reside with the holders of equity investment at risk. However, CERC is not considered the primary beneficiary of Enable since it does not have the power to direct the activities of Enable that are considered most significant to the economic performance of Enable.

Other investments, excluding marketable securities, are carried at cost.

(c) Revenues

CERC records revenue for natural gas sales and services under the accrual method and these revenues are recognized upon delivery to customers. Natural gas sales not billed by month-end are accrued based upon estimated purchased gas volumes, estimated lost and unaccounted for gas and currently effective tariff rates.

(d) Long-lived Assets and Intangibles

CERC records property, plant and equipment at historical cost. CERC expenses repair and maintenance costs as incurred.

CERC periodically evaluates long-lived assets, including property, plant and equipment and specifically identifiable intangibles, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, compared to the carrying value of the assets.

(e) Regulatory Assets and Liabilities

CERC applies the guidance for accounting for regulated operations to the Natural Gas Distribution business segment. CERC's rate-regulated subsidiaries may collect revenues subject to refund pending final determination in rate proceedings. In connection with such revenues, estimated rate refund liabilities are recorded which reflect management's current judgment of the ultimate outcomes of the proceedings.

CERC had current regulatory assets of $70 million and $21 million as of December 31, 2016 and 2015, respectively, included in other current assets in its Consolidated Balance Sheets. CERC had current regulatory liabilities of $11 million and $55 million as of December 31, 2016 and 2015, respectively, included in other current liabilities in its Consolidated Balance Sheets.

CERC's rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. As of December 31, 2016 and 2015, these removal costs of $665 million and $632 million, respectively, are classified as regulatory liabilities in the Consolidated Balance Sheets. In addition, a portion of the amount of removal costs that relate to AROs has been reclassified from a regulatory liability to an asset retirement liability in accordance with accounting guidance for AROs.

(f) Depreciation and Amortization Expense

Depreciation and amortization is computed using the straight-line method based on economic lives or regulatory-mandated recovery periods. Amortization expense includes amortization of regulatory assets and other intangibles.

(g) Capitalization of Interest and AFUDC

Interest and AFUDC are capitalized as a component of projects under construction and are amortized over the assets' estimated useful lives once the assets are placed in service. AFUDC represents the composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction for subsidiaries that apply the guidance for accounting for regulated operations. Although AFUDC increases both utility plant and earnings, it is realized in cash when the assets are included in rates. During 2016, 2015 and 2014, CERC capitalized interest and AFUDC of $2 million, $2 million and $1 million, respectively.

(h) Income Taxes

CERC is a member of the U.S. federal consolidated income tax return of CenterPoint Energy. CERC reports its income tax provision on a separate entity basis pursuant to a tax sharing agreement with CenterPoint Energy. CERC uses the asset and liability method of accounting for deferred income taxes in accordance with accounting guidance for income taxes. Deferred income tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. A valuation allowance is established against deferred tax assets for which management believes realization is not considered to be more likely than not. Current federal and certain state income taxes are payable to or receivable from CenterPoint Energy. CERC recognizes interest and penalties as a component of income tax expense. CERC reports the income tax provision associated with its interest in Enable in Income tax expense (benefit) in its Statements of Consolidated Income.

(i) Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount and do not bear interest. It is the policy of management to review the outstanding accounts receivable monthly, as well as the bad debt write-offs experienced in the past, and establish an allowance for doubtful accounts. Account balances are charged off against the allowance when management determines it is probable the receivable will not be recovered. The provision for doubtful accounts in CERC's Statements of Consolidated Income for 2016, 2015 and 2014 was $7 million, $19 million and $20 million, respectively.

(j) Inventory

Inventory consists principally of materials and supplies and natural gas. Materials and supplies are valued at the lower of average cost or market. Materials and supplies are recorded to inventory when purchased and subsequently charged to expense or capitalized to plant when installed. Natural gas inventories of CERC's Energy Services business segment are valued at the lower of average cost or market. Natural gas inventories of CERC's Natural Gas Distribution business segment are primarily valued at weighted average cost. During 2016, 2015 and 2014, CERC recorded $1 million, $4 million and $8 million, respectively, in write-downs of natural gas inventory to the lower of average cost or market.

(k) Derivative Instruments

CERC is exposed to various market risks. These risks arise from transactions entered into in the normal course of business. CERC utilizes derivative instruments such as physical forward contracts, swaps and options to mitigate the impact of changes in commodity prices and weather on its operating results and cash flows. Such derivatives are recognized in CERC's Consolidated Balance Sheets at their fair value unless CERC elects the normal purchase and sales exemption for qualified physical transactions. A derivative may be designated as a normal purchase or normal sale if the intent is to physically receive or deliver the product for use or sale in the normal course of business.

CenterPoint Energy has a Risk Oversight Committee composed of corporate and business segment officers that oversees commodity price, weather and credit risk activities, including CERC's marketing, risk management services and hedging activities. The committee's duties are to establish CERC's commodity risk policies, allocate board-approved commercial risk limits, approve the use of new products and commodities, monitor positions and ensure compliance with CERC's risk management policies and procedures and limits established by CenterPoint Energy's board of directors.

CERC's policies prohibit the use of leveraged financial instruments. A leveraged financial instrument, for this purpose, is a transaction involving a derivative whose financial impact will be based on an amount other than the notional amount or volume of the instrument.

(l) Environmental Costs

CERC expenses or capitalizes environmental expenditures, as appropriate, depending on their future economic benefit. CERC expenses amounts that relate to an existing condition caused by past operations that do not have future economic benefit. CERC records undiscounted liabilities related to these future costs when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated.

(m) Statements of Consolidated Cash Flows

For purposes of reporting cash flows, CERC considers cash equivalents to be short-term, highly-liquid investments with maturities of three months or less from the date of purchase.

CERC considers distributions received from equity method investments which do not exceed cumulative equity in earnings subsequent to the date of investment to be a return on investment and classifies these distributions as operating activities in the Statements of Consolidated Cash Flows. CERC considers distributions received from equity method investments in excess of cumulative equity in earnings subsequent to the date of investment to be a return of investment and classifies these distributions as investing activities in the Statements of Consolidated Cash Flows.

(n) New Accounting Pronouncements

In February 2015, the FASB issued ASU No. 2015-02, *Consolidation (Topic 810): Amendments to the Consolidation Analysis* (ASU 2015-02). ASU 2015-02 changes the analysis that reporting organizations must perform to evaluate whether they should consolidate certain legal entities, such as limited partnerships. The changes include, among others, modification of the evaluation of whether limited partnerships and similar legal entities are VIEs or voting interest entities and elimination of the presumption that a general partner should consolidate a limited partnership. ASU 2015-02 does not amend the related party guidance for situations in which power is shared between two or more entities that hold interests in a VIE. CERC adopted ASU 2015-02 on January 1, 2016, which did not have a material impact on its financial position, results of operations, cash flows and disclosures.

In April 2015, the FASB issued ASU No. 2015-03, *Interest-Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Cost* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by ASU 2015-03. CERC adopted ASU 2015-03 retrospectively on January 1, 2016, which resulted in a reduction of other long-term assets, indexed debt and total long-term debt on its Consolidated Balance Sheets. CERC had debt issuance costs, excluding amounts related to credit facility arrangements, of $10 million and $12 million as a reduction to long-term debt on its Consolidated Balance Sheets as of December 31, 2016 and 2015, respectively.

In May 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07). ASU 2015-07 removes the requirement to categorize within the fair value hierarchy investments for which fair values are measured at NAV using the practical expedient. Entities will be required to disclose the fair value of investments measured using the NAV practical expedient so that financial statement users can reconcile amounts reported in the fair value hierarchy table to amounts reported on the balance sheet. CERC retrospectively adopted ASU 2015-07 on January 1, 2016, which impacts its employee benefit plan disclosures. See Note 7 for the impacts on the employee benefit plan disclosures. This standard did not have an impact on CERC’s financial position, results of operations or cash flows.

In September 2015, the FASB issued ASU No. 2015-16, *Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments* (ASU 2015-16). ASU 2015-16 eliminates the requirement for an acquirer in a business combination to account for measurement-period adjustments retrospectively. Instead, an acquirer would recognize a measurement-period adjustment during the period in which the amount of the adjustment is determined. CERC prospectively adopted ASU 2015-16 on January 1, 2016, which did not have an impact on its financial position, results of operations or cash flows.

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments-Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities* (ASU 2016-01). ASU 2016-01 requires equity investments that do not result in consolidation and are not accounted for under the equity method to be measured at fair value and to recognize any changes in fair value in net income unless the investments qualify for the new practicability exception. It does not change the guidance for classifying and measuring investments in debt securities and loans. ASU 2016-01 also changes certain disclosure requirements and other aspects related to recognition and measurement of financial assets and financial liabilities. ASU 2016-01 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. As of the first reporting period in which the guidance is adopted, a cumulative-effect adjustment to beginning retained earnings will be made, with two features that will be adopted prospectively. CERC is currently assessing the impact that this standard will have on its financial position, results of operations, cash flows and disclosures.

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 provides a comprehensive new lease model that requires lessees to recognize assets and liabilities for most leases and would change certain aspects of lessor accounting. ASU 2016-02 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018, with early adoption permitted. A modified retrospective adoption approach is required. CERC is currently assessing the impact that this standard will have on its financial position, results of operations, cash flows and disclosures.

In 2016, the FASB issued ASUs which amended ASU No. 2014-09, *Revenue from Contracts with Customers (Topic 606)*. ASU 2014-09, as amended, provides a comprehensive new revenue recognition model that requires revenue to be recognized in a manner that depicts the transfer of goods or services to a customer at an amount that reflects the consideration expected to be received in exchange for those goods or services. Early adoption is not permitted, and entities have the option of using either a full retrospective or a modified retrospective adoption approach. CERC is currently evaluating its revenue streams under these ASUs and has not yet identified any significant changes as the result of these new standards. A substantial amount of CERC’s revenues are tariff based, which we do not anticipate will be significantly impacted by these ASUs. CERC is considering the impacts of the new guidance on its ability to recognize revenue for certain contracts when collectability is uncertain and its accounting for contributions in aid of construction. CERC expects to adopt these ASUs on January 1, 2018 and is evaluating the method of adoption.

In August 2016, the FASB issued ASU No. 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments* (ASU 2016-15). ASU 2016-15 provides clarifying guidance on the classification of certain cash receipts and payments in the statement of cash flows and eliminates the variation in practice related to such classifications. ASU 2016-15 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017, with early adoption permitted. A retrospective adoption approach is required. CERC is currently assessing the impact that this standard will have on its statement of cash flows.

In November 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* (ASU 2016-18). ASU 2016-18 requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, restricted cash and restricted cash equivalents. As a result, the statement of cash flows will no longer present transfers between cash and cash equivalents and restricted cash and restricted cash equivalents. When cash, cash equivalents, restricted cash and restricted cash equivalents are presented in more than one line item on the balance sheet, the new guidance requires a reconciliation of the totals in the statement of cash flows to the related captions in the balance sheet. ASU 2016-18 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017, with early adoption permitted. A retrospective adoption approach is required. CERC is currently assessing the impact that this standard will have on its statement of cash flows and disclosures.

In January 2017, the FASB issued ASU No. 2017-01, *Business Combinations (Topic 805): Clarifying the Definition of a Business* (ASU 2017-01). ASU 2017-01 revises the definition of a business. If substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or a group of similar identifiable assets, then under ASU 2017-01, the asset or group of assets is not a business. The guidance also requires a business to include at least one substantive process and narrows the definition of outputs to be more closely aligned with how outputs are described in ASC 606. ASU 2017-01 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017, with early adoption permitted in certain circumstances. A prospective adoption approach is required. ASU 2017-01 could have a potential impact on CERC’s accounting for future acquisitions.

In January 2017, the FASB issued ASU No. 2017-04, *Intangibles-Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment* (ASU 2017-04). ASU 2017-04 eliminates Step 2 of the goodwill impairment test, which requires a hypothetical purchase price allocation. A goodwill impairment will now be the amount by which a reporting unit’s carrying value exceeds its fair value, not to exceed the carrying amount of goodwill. ASU 2017-04 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019, with early adoption permitted. A prospective adoption approach is required. ASU 2017-04 will have an impact on CERC’s future calculation of goodwill impairments if an impairment is identified.

Management believes that other recently issued standards, which are not yet effective, will not have a material impact on CERC’s consolidated financial position, results of operations or cash flows upon adoption.

(o) Other Current Assets and Liabilities

Included in other current assets on the Consolidated Balance Sheets as of December 31, 2016 and 2015 were less than $1 million and $31 million, respectively, of margin deposits and $40 million and $12 million, respectively, of under-recovered gas cost. Included in other current liabilities on the Consolidated Balance Sheets as of December 31, 2016 and 2015 were $10 million and $55 million, respectively, of over-recovered gas cost.

(3) Property, Plant and Equipment

(a) Property, Plant and Equipment

Property, plant and equipment includes the following:

	Weighted Average Useful Lives (in years)	December 31, 2016	December 31, 2015
		(in millions)	
Natural Gas Distribution	32	$ 6,219	$ 5,762
Energy Services	25	83	86
Other property	9	49	50
Total		6,351	5,898
Accumulated depreciation and amortization:			
Natural Gas Distribution		1,722	1,575
Energy Services		29	34
Other property		31	31
Total accumulated depreciation and amortization		1,782	1,640
Property, plant and equipment, net		$ 4,569	$ 4,258

(b) Depreciation and Amortization

The following table presents depreciation and amortization expense for 2016, 2015 and 2014:

	Year Ended December 31, 2016	2015	2014
		(in millions)	
Depreciation expense	$ 230	$ 211	$ 195
Amortization expense	19	16	11
Total depreciation and amortization expense	$ 249	$ 227	$ 206

(c) AROs

A reconciliation of the changes in the ARO liability is as follows:

	December 31, 2016	2015
	(in millions)	
Beginning balance	$ 156	$ 139
Accretion expense	8	5
Revisions in estimates of cash flows	5	12
Ending balance	$ 169	$ 156

CERC recorded AROs associated with the removal of asbestos and asbestos-containing material in its buildings. CERC also recorded AROs relating to gas pipelines abandoned in place. The estimates of future liabilities were developed using historical information, and where available, quoted prices from outside contractors.

The increase of $5 million in the ARO from the revision in estimates in 2016 is primarily attributable to an increase in the labor rate associated with the abandonment of gas mains. The increase of $12 million in the ARO from the revision in estimates in 2015 is primarily attributable to a reduction in the estimated service lives of steel and plastic pipe. There were no material additions or settlements during the years ended December 31, 2016 or 2015.

(4) Acquisition

On April 1, 2016, CES, a wholly-owned subsidiary of CERC, closed the previously announced agreement to acquire the retail energy services business and natural gas wholesale assets of Continuum. After working capital adjustments, the final purchase price was $102 million and allocated to identifiable assets acquired and liabilities assumed based on their estimated fair values on the acquisition date.

The following table summarizes the final purchase price allocation and the fair value amounts recognized for the assets acquired and liabilities assumed related to the acquisition:

		(in millions)
Total purchase price consideration	$	102
Receivables	$	76
Derivative assets		38
Property and equipment		1
Identifiable intangibles		38
Total assets acquired		153
Accounts payable		49
Derivative liabilities		24
Total liabilities assumed		73
Identifiable net assets acquired		80
Goodwill		22
Net assets acquired	$	102

The goodwill of $22 million resulting from the acquisition reflects the excess of the purchase price over the fair value of the net identifiable assets acquired. The goodwill recorded as part of the acquisition primarily reflects the value of the complementary operational and geographic footprints, along with the scale, geographic reach and expanded capabilities.

Identifiable intangible assets were recorded at estimated fair value as determined by management based on available information, which includes a valuation prepared by an independent third party. The significant assumptions used in arriving at the estimated identifiable intangible asset values included management’s estimates of future cash flows, the discount rate which is based on the weighted average cost of capital for comparable publicly traded guideline companies and projected customer attrition rates. The useful lives for the identifiable intangible assets were determined using methods that approximate the pattern of economic benefit provided by the utilization of the assets.

The estimated fair value of the identifiable intangible assets and related useful lives as included in the final purchase price allocation include:

		Estimate Fair Value	Estimate Useful Life
		(in millions)	(in years)
Customer relationships	$	34	15
Covenants not to compete		4	4
Total identifiable intangibles	$	38	

Amortization expense related to the above identifiable intangible assets was $3 million for the year ended December 31, 2016.

Revenues of approximately $466 million and operating income of approximately $1 million attributable to the acquisition are included in CERC’s Statements of Consolidated Income for the year ended December 31, 2016.

As Continuum was a non-public company that did not prepare interim financial information and the acquisition included the purchase of both businesses and assets, the historical financial information for the businesses and assets acquired was impracticable to obtain. As a result, pro forma results of the acquired businesses and assets are not presented.

(5) Goodwill

Goodwill by reportable business segment as of December 31, 2015 and changes in the carrying amount of goodwill as of December 31, 2016 are as follows:

	December 31, 2015	Continuum Acquisition (1)	December 31, 2016
		(in millions)	
Natural Gas Distribution	$ 746	$ —	$ 746
Energy Services	83 (2)	22	105 (2)
Other Operations	11	—	11
Total	$ 840	$ 22	$ 862

(1) See Note 4.

(2) Amount presented is net of the accumulated goodwill impairment charge of $252 million.

CERC performs goodwill impairment tests at least annually and evaluates goodwill when events or changes in circumstances indicate that its carrying value may not be recoverable. The impairment evaluation for goodwill is performed by using a two-step process. In the first step, the fair value of each reporting unit is compared with the carrying amount of the reporting unit, including goodwill. The estimated fair value of the reporting unit is generally determined on the basis of discounted cash flows. 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 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.

CERC performed its annual goodwill impairment test in the third quarter of each of 2016 and 2015 and determined, based on the results of the first step, that no goodwill impairment charge was required for any reportable segment. Other intangibles were not material as of December 31, 2016 and 2015.

(6) Regulatory Accounting

The following is a list of regulatory assets/liabilities reflected on CERC's Consolidated Balance Sheets as of December 31, 2016 and 2015:

	December 31,	
	2016	2015
	(in millions)	
Regulatory assets in other long-term assets (1)	$ 125	$ 105
Regulatory liabilities	(769)	(734)
Net	$ (644)	$ (629)

(1) NGD's actuarially determined pension and other postemployment expense in excess of the amount being recovered through rates is being deferred for rate making purposes. Deferred pension and other postemployment expenses of $6 million and $5 million as of December 31, 2016 and 2015, respectively, were not earning a return. Other regulatory assets that are not earning a return were not material as of December 31, 2016 or 2015.

(7) Employee Benefit Plans

(a) Pension Plans

Substantially all of CERC's employees participate in CenterPoint Energy's qualified non-contributory defined benefit pension plan. Under the cash balance formula, participants accumulate a retirement benefit based upon 5% of eligible earnings and accrued interest.

CenterPoint Energy's funding policy is to review amounts annually in accordance with applicable regulations in order to achieve adequate funding of projected benefit obligations. Pension expense is allocated to CERC based on covered employees. This calculation is intended to allocate pension costs in the same manner as a separate employer plan. Assets of the plan are not segregated or restricted by CenterPoint Energy's participating subsidiaries. CERC recognized pension expense of $35 million, $24 million and $27 million for the years ended December 31, 2016, 2015 and 2014, respectively.

In addition to the plan, CERC participates in CenterPoint Energy's non-qualified benefit restoration plans, which allow participants to receive the benefits to which they would have been entitled under CenterPoint Energy's non-contributory pension plan except for federally mandated limits on qualified plan benefits or on the level of compensation on which qualified plan benefits may be calculated. The expense associated with the non-qualified pension plan was $3 million, $2 million and $2 million for the years ended December 31, 2016, 2015 and 2014, respectively.

(b) Savings Plan

CERC participates in CenterPoint Energy's qualified savings plan, which includes a cash or deferred arrangement under Section 401(k) of the Internal Revenue Code of 1986, as amended. Under the plan, participating employees may contribute a portion of their compensation, on a pre-tax or after-tax basis, generally up to a maximum of 50% of eligible compensation. CERC matches 100% of the first 6% of each employee's compensation contributed. The matching contributions are fully vested at all times.

Participating employees may elect to invest all (prior to January 1, 2016) or a portion of their contributions to the plan in CenterPoint Energy, Inc. common stock, to have dividends reinvested in additional shares or to receive dividend payments in cash on any investment in CenterPoint Energy, Inc. common stock, and to transfer all or part of their investment in CenterPoint Energy, Inc. common stock to other investment options offered by the plan.

Effective January 1, 2016 the savings plan was amended to limit the percentage of future contributions that could be invested in CenterPoint Energy, Inc. common stock to 25% and to prohibit transfers of account balances where the transfer would result in more than 25% of a participant's total account balance invested in CenterPoint Energy, Inc. common stock.

The savings plan has significant holdings of CenterPoint Energy, Inc. common stock. As of December 31, 2016, 14,216,986 shares of CenterPoint Energy, Inc. common stock were held by the savings plan, which represented approximately 17% of its investments. Given the concentration of the investments in CenterPoint Energy, Inc. common stock, the savings plan and its participants have market risk related to this investment.

CenterPoint Energy allocates to CERC the savings plan benefit expense related to CERC's employees. Savings plan benefit expense was $16 million, $14 million and $20 million for the years ended December 31, 2016, 2015 and 2014, respectively.

(c) Postretirement Benefits

CERC's employees participate in CenterPoint Energy's plans, which provide certain healthcare and life insurance benefits for retired employees on both a contributory and non-contributory basis. Employees become eligible for these benefits if they have met certain age and service requirements at retirement, as defined in the plans. Such benefit costs are accrued over the active service period of employees. CERC is required to fund a portion of its obligations in accordance with rate orders. All other obligations are funded on a pay-as-you-go basis.

The net postretirement benefit cost includes the following components:

	Year Ended December 31,		
	2016	2015	2014
	(in millions)		
Service cost — benefits earned during the period	$ 1	$ 1	$ 1
Interest cost on accumulated benefit obligation	4	5	5
Expected return on plan assets	(1)	(1)	(1)
Amortization of prior service cost	—	1	1
Amortization of net loss	1	1	1
Curtailment (1)	(1)	—	—
Net postretirement benefit cost	$ 4	$ 7	$ 7

(1) Effective January 1, 2017, a change in retiree medical coverage for Medicare eligible post-65 retirees from self-insured to a Medicare Advantage Program, an insured benefit, was implemented. A curtailment gain was recognized in October 2016 related to this implementation.

CERC used the following assumptions to determine net postretirement benefit costs:

	Year Ended December 31,		
	2016	2015	2014
Discount rate	4.35%	3.90%	4.75%
Expected return on plan assets	3.95%	4.05%	3.10%

In determining net periodic benefits cost, CERC uses fair value, as of the beginning of the year, as its basis for determining expected return on plan assets.

Following are reconciliations of CERC's beginning and ending balances of its postretirement benefit plan's benefit obligation, plan assets and funded status for 2016 and 2015. The measurement dates for plan assets and obligations were December 31, 2016 and 2015.

	December 31,	
	2016	2015
	(in millions, except for actuarial assumptions)	
Change in Benefit Obligation		
Accumulated benefit obligation, beginning of year	$ 101	$ 126
Service cost	1	1
Interest cost	4	5
Benefits paid	(13)	(12)
Participant contributions	5	4
Medicare reimbursement	1	1
Plan amendment (1)	10	(5)
Actuarial (gain) loss	6	(19)
Accumulated benefit obligation, end of year	$ 115	$ 101
Change in Plan Assets		
Plan assets, beginning of year	$ 25	$ 26
Benefits paid	(13)	(12)
Employer contributions	7	7
Participant contributions	5	4
Actual investment return	1	—
Plan assets, end of year	$ 25	$ 25
Amounts Recognized in Balance Sheets		
Current liabilities-other	$ (4)	$ (6)
Other liabilities-benefit obligations	(86)	(70)
Net liability, end of year	$ (90)	$ (76)
Actuarial Assumptions		
Discount rate	4.15%	4.35%
Expected long-term return on assets	3.60%	3.95%
Healthcare cost trend rate assumed for the next year - Pre 65	5.75%	6.00%
Healthcare cost trend rate assumed for the next year - Post 65	10.65%	5.50%
Prescription cost trend rate assumed for the next year	10.75%	11.00%
Rate to which the cost trend rate is assumed to decline (ultimate trend rate)	4.50%	5.00%
Year that the healthcare rate reaches the ultimate trend rate	2024	2024
Year that the prescription drug rate reaches the ultimate trend rate	2024	2024

(1) The postretirement plan was amended in 2016 to change the retiree medical coverage for Medicare eligible post-65 retirees from self-insured to a Medicare Advantage Program, an insured benefit which became effective January 1, 2017.

The discount rate assumption was determined by matching the projected cash flows of CenterPoint Energy's plans against a hypothetical yield curve of high-quality corporate bonds represented by a series of annualized individual discount rates from one-half to 99 years.

The expected rate of return assumption was developed using the targeted asset allocation of CenterPoint Energy's plans and the expected return for each asset class, based on the long-term capital market assumptions, adjusted for investment fees and diversification effects, in addition to expected inflation.

For measurement purposes, medical costs are assumed to increase to 5.75% and 10.65% for the pre-65 and post-65 retirees during 2017, respectively, and the prescription cost is assumed to increase to 10.75% during 2017, after which these rates decrease until reaching the ultimate trend rate of 4.50% in 2024.

CERC's changes in accumulated comprehensive income (loss) related to postretirement and other postemployment plans are as follows:

	Year Ended December 31,	
	2016	**2015**
	(in millions)	
Beginning Balance	$ 9	$ 1
Other comprehensive income (loss) before reclassifications (1)	(10)	13
Amounts reclassified from accumulated other comprehensive income:		
Actuarial gains (2)	—	1
Tax benefit (expense)	4	(6)
Net current period other comprehensive income (loss)	(6)	8
Ending Balance	$ 3	$ 9

(1) Total other comprehensive income (loss) related to the remeasurement of pension, postretirement and other postemployment plans.

(2) These accumulated other comprehensive components are included in the computation of net periodic cost.

Amounts recognized in accumulated other comprehensive (income) loss consist of the following:

	December 31,	
	2016	**2015**
	(in millions)	
Unrecognized actuarial loss	$ 5	$ 3
Unrecognized prior service cost (credit)	7	(1)
Total recognized in accumulated other comprehensive loss	12	2
Less: deferred tax benefit (1)	(15)	(11)
Net amount recognized in accumulated other comprehensive income	$ (3)	$ (9)

(1) CERC's postretirement benefit obligation is reduced by the impact of previously non-taxable government subsidies under the Medicare Prescription Drug Act. Because the subsidies were non-taxable, the temporary difference used in measuring the deferred tax impact was determined on the unrecognized losses excluding such subsidies.

The changes in plan assets and benefit obligations recognized in other comprehensive loss during 2016 are as follows:

		Postretirement Benefits
		(in millions)
Net loss	$	2
Amortization of prior service cost		8
Total recognized in other comprehensive loss	$	10

The total expense recognized in net periodic costs and other comprehensive gains was $14 million for postretirement benefits for the year ended December 31, 2016.

CERC expects to recognize $1 million of amortization of prior service cost in accumulated other comprehensive loss as components of net periodic benefit cost during 2017.

Assumed healthcare cost trend rates have a significant effect on the reported amounts for CERC's postretirement benefit plans. A 1% change in the assumed healthcare cost trend rate would have the following effects:

		1% Increase		1% Decrease
	(in millions)			
Effect on the postretirement benefit obligation	$	4	$	4
Effect on the total of service and interest cost		—		—

In managing the investments associated with the postretirement benefit plan, CERC's objective is to preserve and enhance the value of plan assets while maintaining an acceptable level of volatility. These objectives are expected to be achieved through an investment strategy that manages liquidity requirements while maintaining a long-term horizon in making investment decisions and efficient and effective management of plan assets.

As part of the investment strategy discussed above, CERC maintained the following asset allocation ranges for its postretirement benefit plan as of December 31, 2016:

U.S. equity	15–25%
International equity	2–12%
Fixed income	68–78%
Cash	0–2%

The fair values of CERC's postretirement plan assets at December 31, 2016 and 2015, by asset category are as follows:

	Fair Value Measurements as of December 31, 2016							
	Quoted Prices in Active Markets for Identical Assets (Level 1)		Significant Observable Inputs (Level 2)		Significant Unobservable Inputs (Level 3)		Total	
Mutual funds (1)	$	25	$	—	$	—	$	25
Total	$	25	$	—	$	—	$	25

(1) 73% of the amount invested in mutual funds was in fixed income securities; 20% was in U.S. equities and 7% was in international equities.

	Fair Value Measurements as of December 31, 2015			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Mutual funds (1)	$ 25	$ —	$ —	$ 25
Total	$ 25	$ —	$ —	$ 25

(1) 70% of the amount invested in mutual funds was in fixed income securities; 23% was in U.S. equities and 7% was in international equities.

CERC expects to contribute $5 million to its postretirement benefits plan in 2017. The following benefit payments are expected to be made by the postretirement benefit plan:

	Benefit Payments
	(in millions)
2017	$ 5
2018	6
2019	7
2020	8
2021	8
2022-2026	43

(d) Postemployment Benefits

CERC participates in CenterPoint Energy’s plan that provides postemployment benefits for certain former or inactive employees, their beneficiaries and covered dependents, after employment but before retirement (primarily healthcare and life insurance benefits for participants in the long-term disability plan). CERC recorded postemployment benefit expense of $3 million, $4 million and $2 million for the years ended December 31, 2016, 2015 and 2014, respectively. Amounts relating to postemployment benefits included in Benefit Obligations in the accompanying Consolidated Balance Sheets as of both December 31, 2016 and 2015 were $14 million.

(e) Other Non-Qualified Plans

CERC participates in CenterPoint Energy’s deferred compensation plans that provide benefits payable to directors, officers and certain key employees or their designated beneficiaries at specified future dates, upon termination, retirement or death. Benefit payments are made from the general assets of CERC. During 2016, 2015 and 2014, the benefit expense relating to these plans was less than $1 million each year. Amounts relating to deferred compensation plans included in Benefit Obligations in the accompanying Consolidated Balance Sheets as of both December 31, 2016 and 2015 were $3 million.

(f) Other Employee Matters

As of December 31, 2016, approximately 34% of CERC’s employees were covered by collective bargaining agreements. The collective bargaining agreement with the Professional Employees International Union Local 12, which covers approximately 3% of CERC’s employees, expired in May of 2016. CERC successfully negotiated the follow-on agreement in 2016. The new collective bargaining agreement with the Professional Employees International Union Local 12 expires in May of 2021.

The collective bargaining agreements with Gas Workers Union, Local 340 and the IBEW, Local 949, covering approximately 19% of CERC’s employees, will expire in April and December of 2020, respectively. These two agreements were last negotiated in 2015.

The two collective bargaining agreements with the United Steelworkers Union, Locals 13-227 and 13-1, which cover approximately 12% of CERC’s employees, are scheduled to expire in June and July of 2017, respectively. CERC believes it has good relationships with these bargaining units and expects to negotiate new agreements in 2017.

(8) Related Party Transactions

CERC participates in a money pool through which it can borrow or invest on a short-term basis. Funding needs are aggregated and external borrowing or investing is based on the net cash position. The net funding requirements of the money pool are expected to be met with borrowings under CenterPoint Energy's revolving credit facility or the sale of CenterPoint Energy's commercial paper. CERC had no investments in the money pool as of both December 31, 2016 and December 31, 2015, which are included in accounts and notes receivable–affiliated companies in the Consolidated Balance Sheets. Affiliate related net interest income (expense) was not material for the years ended December 31, 2016, 2015 and 2014.

CenterPoint Energy provides some corporate services to CERC. The costs of services have been charged directly to CERC using methods that management believes are reasonable. These methods include negotiated usage rates, dedicated asset assignment and proportionate corporate formulas based on operating expenses, assets, gross margin, employees and a composite of assets, gross margin and employees. Houston Electric provides a number of services to CERC. These services are billed at actual cost, either directly or as an allocation, and include fleet services, shop services, geographic services, surveying and right-of-way services, radio communications, data circuit management and field operations. Additionally, CERC provides certain services to Houston Electric. These services are billed at actual cost, either directly or as an allocation and include line locating and other miscellaneous services. These charges are not necessarily indicative of what would have been incurred had CERC not been an affiliate of CenterPoint Energy. Amounts charged to and from CERC for these services were as follows and are included primarily in operation and maintenance expenses:

	Year Ended December 31,		
	2016	**2015**	**2014**
	(in millions)		
Corporate service charges	$ 125	$ 118	$ 115
Charges from Houston Electric for services provided	15	18	17
Billings to Houston Electric for services provided	(7)	(6)	(5)
	$ 133	$ 130	$ 127

Dividends of $643 million, $43 million and $405 million were paid to the parent in 2016, 2015 and 2014, respectively.

See Note 11 for related party transactions with Enable.

(9) Derivative Instruments

CERC is exposed to various market risks. These risks arise from transactions entered into in the normal course of business. CERC utilizes derivative instruments such as physical forward contracts, swaps and options to mitigate the impact of changes in commodity prices and weather on its operating results and cash flows.

(a) Non-Trading Activities

Derivative Instruments. CERC enters into certain derivative instruments to mitigate the effects of commodity price movements. These financial instruments do not qualify or are not designated as cash flow or fair value hedges.

Weather Hedges. CERC has weather normalization or other rate mechanisms that mitigate the impact of weather on NGD in Arkansas, Louisiana, Mississippi, Minnesota and Oklahoma. NGD in Texas does not have such mechanisms, although fixed customer charges are historically higher in Texas compared to NGD's other jurisdictions. As a result, fluctuations from normal weather may have a positive or negative effect on NGD's results in Texas.

CERC has historically entered into heating-degree day swaps for certain NGD jurisdictions to mitigate the effect of fluctuations from normal weather on its results of operations and cash flows for the winter heating season, which contained a bilateral dollar cap of $16 million in 2014–2015. However, NGD did not enter into heating-degree day swaps for the 2015–2016 winter season as a result of NGD's Minnesota division implementing a full decoupling pilot in July 2015. The swaps are based on 10-year normal weather. During the years ended December 31, 2016, 2015 and 2014, CERC recognized losses of $-0-, $4 million and $10 million, respectively, related to these swaps. Weather hedge gains and losses are included in revenues in the Statements of Consolidated Income.

(b) Derivative Fair Values and Income Statement Impacts

The following tables present information about CERC's derivative instruments and hedging activities. The first four tables provide a balance sheet overview of CERC's Derivative Assets and Liabilities as of December 31, 2016 and 2015, while the last table provides a breakdown of the related income statement impacts for the years ending December 31, 2016, 2015 and 2014.

Fair Value of Derivative Instruments

	December 31, 2016		
Total derivatives not designated as hedging instruments	**Balance Sheet Location**	**Derivative Assets Fair Value**	**Derivative Liabilities Fair Value**
		(in millions)	
Natural gas derivatives (1) (2) (3)	Current Assets: Non-trading derivative assets	$ 79	$ 14
Natural gas derivatives (1) (2) (3)	Other Assets: Non-trading derivative assets	24	5
Natural gas derivatives (1) (2) (3)	Current Liabilities: Non-trading derivative liabilities	2	43
Natural gas derivatives (1) (2) (3)	Other Liabilities: Non-trading derivative liabilities	—	5
Total		$ 105	$ 67

(1) The fair value shown for natural gas contracts is comprised of derivative gross volumes totaling 1,035 Bcf or a net 59 Bcf long position. Of the net long position, basis swaps constitute a net 126 Bcf long position.

(2) Natural gas contracts are presented on a net basis in the Consolidated Balance Sheets as they are subject to master netting arrangements. This netting applies to all undisputed amounts due or past due and causes derivative assets (liabilities) to be ultimately presented net in a liability (asset) account within the Consolidated Balance Sheets. The net of total non-trading natural gas derivative assets and liabilities was a $24 million asset as shown on CERC's Consolidated Balance Sheets (and as detailed in the table below), and was comprised of the natural gas contracts derivative assets and liabilities separately shown above, impacted by collateral netting of $14 million.

(3) Derivative Assets and Derivative Liabilities include no material amounts related to physical forward transactions with Enable.

Offsetting of Natural Gas Derivative Assets and Liabilities

	December 31, 2016		
	Gross Amounts Recognized (1)	**Gross Amounts Offset in the Consolidated Balance Sheets**	**Net Amount Presented in the Consolidated Balance Sheets (2)**
		(in millions)	
Current Assets: Non-trading derivative assets	$ 81	$ (30)	$ 51
Other Assets: Non-trading derivative assets	24	(5)	19
Current Liabilities: Non-trading derivative liabilities	(57)	16	(41)
Other Liabilities: Non-trading derivative liabilities	(10)	5	(5)
Total	$ 38	$ (14)	$ 24

(1) Gross amounts recognized include some derivative assets and liabilities that are not subject to master netting arrangements.

(2) The derivative assets and liabilities on the Consolidated Balance Sheets exclude accounts receivable or accounts payable that, should they exist, could be used as offsets to these balances in the event of a default.

Fair Value of Derivative Instruments

Total derivatives not designated as hedging instruments	Balance Sheet Location	December 31, 2015 Derivative Assets Fair Value	Derivative Liabilities Fair Value
		(in millions)	
Natural gas derivatives (1) (2) (3)	Current Assets: Non-trading derivative assets	$ 90	$ 2
Natural gas derivatives (1) (2) (3)	Other Assets: Non-trading derivative assets	36	—
Natural gas derivatives (1) (2) (3)	Current Liabilities: Non-trading derivative liabilities	10	60
Natural gas derivatives (1) (2) (3)	Other Liabilities: Non-trading derivative liabilities	4	25
Total		$ 140	$ 87

(1) The fair value shown for natural gas contracts is comprised of derivative gross volumes totaling 767 Bcf or a net 112 Bcf long position. Of the net long position, basis swaps constitute 133 Bcf.

(2) Natural gas contracts are presented on a net basis in the Consolidated Balance Sheets. Natural gas contracts are subject to master netting arrangements. This netting applies to all undisputed amounts due or past due and causes derivative assets (liabilities) to be ultimately presented net in a liability (asset) account within the Consolidated Balance Sheets. The net of total non-trading derivative assets and liabilities was a $109 million asset as shown on CERC's Consolidated Balance Sheets (and as detailed in the table below), and was comprised of the natural gas contracts derivative assets and liabilities separately shown above, impacted by collateral netting of $56 million.

(3) Derivative Assets and Derivative Liabilities include no material amounts related to physical forward transactions with Enable.

Offsetting of Natural Gas Derivative Assets and Liabilities

	December 31, 2015 Gross Amounts Recognized (1)	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amount Presented in the Consolidated Balance Sheets (2)
		(in millions)	
Current Assets: Non-trading derivative assets	$ 100	$ (11)	$ 89
Other Assets: Non-trading derivative assets	40	(4)	36
Current Liabilities: Non-trading derivative liabilities	(62)	51	(11)
Other Liabilities: Non-trading derivative liabilities	(25)	20	(5)
Total	$ 53	$ 56	$ 109

(1) Gross amounts recognized include some derivative assets and liabilities that are not subject to master netting arrangements.

(2) The derivative assets and liabilities on the Consolidated Balance Sheets exclude accounts receivable or accounts payable that, should they exist, could be used as offsets to these balances in the event of a default.

Realized and unrealized gains and losses on natural gas derivatives are recognized in the Statements of Consolidated Income as revenue for retail sales derivative contracts and as natural gas expense for financial natural gas derivatives and non-retail related physical natural gas derivatives.

Income Statement Impact of Derivative Activity

Total derivatives not designated as hedging instruments	Income Statement Location	Year Ended December 31, 2016	2015	2014
			(in millions)	
Natural gas derivatives	Gains (Losses) in Revenue	$ (18)	$ 134	$ 35
Natural gas derivatives	Gains (Losses) in Expense: Natural Gas	70	(105)	11
Total		$ 52	$ 29	$ 46

(c) Credit Risk Contingent Features

CERC enters into financial derivative contracts containing material adverse change provisions. These provisions could require CERC to post additional collateral if the S&P or Moody's credit ratings of CERC are downgraded. The total fair value of the derivative instruments that contain credit risk contingent features that are in a net liability position as of December 31, 2016 and 2015 was $1 million and $3 million, respectively. CERC posted no assets as collateral towards derivative instruments that contain credit risk contingent features as of either December 31, 2016 or 2015. If all derivative contracts (in a net liability position) containing credit risk contingent features were triggered at December 31, 2016 and 2015, $-0- and $2 million, respectively, of additional assets would be required to be posted as collateral.

(d) Credit Quality of Counterparties

In addition to the risk associated with price movements, credit risk is also inherent in CERC's non-trading derivative activities. Credit risk relates to the risk of loss resulting from non-performance of contractual obligations by a counterparty. The following table shows the composition of counterparties to the non-trading derivative assets of CERC as of December 31, 2016 and 2015:

	December 31, 2016		December 31, 2015	
	Investment Grade(1)	Total	Investment Grade(1)	Total
	(in millions)			
Energy marketers	$ 1	$ 4	$ 4	$ 10
Financial institutions	33	33	—	—
End users (2)	2	47	2	115
Total	$ 36	$ 84 (3)	$ 6	$ 125

(1) "Investment grade" is primarily determined using publicly available credit ratings, and considers credit support (including parent company guarantees) and collateral (including cash and standby letters of credit). For unrated counterparties, CERC determines a synthetic credit rating by performing financial statement analysis, and considers contractual rights and restrictions and collateral.

(2) End users are comprised primarily of customers who have contracted to fix the price of a portion of their physical gas requirements for future periods.

(3) The net of total non-trading natural gas derivative assets was $70 million and $125 million as of December 31, 2016 and 2015, respectively, as shown on CERC's Consolidated Balance Sheets, and was comprised of the natural gas contracts derivatives assets separately shown above, impacted by collateral netting of $14 million and $-0- as of December 31, 2016 and 2015, respectively.

(10) Fair Value Measurements

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

Level 1: Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date. The types of assets carried at Level 1 fair value generally are exchange-traded derivatives and equity securities.

Level 2: Inputs, other than quoted prices included in Level 1, are observable for the asset or liability, either directly or indirectly. Level 2 inputs include quoted prices for similar instruments in active markets, and inputs other than quoted prices that are observable for the asset or liability. Fair value assets and liabilities that are generally included in this category are derivatives with fair values based on inputs from actively quoted markets. A market approach is utilized to value CERC's Level 2 assets or liabilities.

Level 3: Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability. Unobservable inputs reflect CERC's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. CERC develops these inputs based on the best information available, including CERC's own data. A market approach is utilized to value CERC's Level 3 assets or liabilities. At December 31, 2016, CERC's Level 3 assets and liabilities are comprised of physical forward contracts and options. Level 3 physical forward contracts are valued using a discounted cash flow model which includes illiquid forward price curve locations (ranging from $2.24 to $7.01 per MMBtu) as an unobservable input. Level 3 options are valued through Black-Scholes (including forward start) option models which include option volatilities (ranging from 0% to 86%) as an unobservable input. CERC's Level 3 derivative assets and liabilities consist of both long and short positions (forwards and options) and their fair value is sensitive to forward prices and volatilities. If forward prices decrease, CERC's long forwards lose value whereas its short forwards gain in value. If volatility decreases, CERC's long options lose value whereas its short options gain in value.

CERC determines the appropriate level for each financial asset and liability on a quarterly basis and recognizes transfers between levels at the end of the reporting period. For the year ended December 31, 2016, there were no transfers between Level 1 and 2. CERC also recognizes purchases of Level 3 financial assets and liabilities at their fair market value at the end of the reporting period.

The following tables present information about CERC's assets and liabilities (including derivatives that are presented net) measured at fair value on a recurring basis and indicate the fair value hierarchy of the valuation techniques utilized by CERC to determine such fair value.

	December 31, 2016				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Adjustments (1)	Balance
			(in millions)		
Assets					
Corporate equities	$ 3	$ —	$ —	$ —	$ 3
Investments, including money market funds (2)	10	—	—	—	10
Natural gas derivatives (3)	11	74	20	(35)	70
Total assets	$ 24	$ 74	$ 20	$ (35)	$ 83
Liabilities					
Natural gas derivatives (3)	$ 4	$ 56	$ 7	$ (21)	$ 46
Total liabilities	$ 4	$ 56	$ 7	$ (21)	$ 46

(1) Amounts represent the impact of legally enforceable master netting arrangements that allow CERC to settle positive and negative positions and also include cash collateral of $14 million held by CES from the same counterparties.

(2) Amounts are included in Other Assets in the Consolidated Balance Sheets.

(3) Natural gas derivatives include no material amounts related to physical forward transactions with Enable.

	December 31, 2015				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Adjustments (1)	Balance
			(in millions)		
Assets					
Corporate equities	$ 2	$ —	$ —	$ —	$ 2
Investments, including money market funds (2)	11	—	—	—	11
Natural gas derivatives (3)	4	115	21	(15)	125
Total assets	$ 17	$ 115	$ 21	$ (15)	$ 138
Liabilities					
Natural gas derivatives (3)	$ 13	$ 65	$ 9	$ (71)	$ 16
Total liabilities	$ 13	$ 65	$ 9	$ (71)	$ 16

(1) Amounts represent the impact of legally enforceable master netting arrangements that allow CERC to settle positive and negative positions and also include cash collateral of $56 million posted with the same counterparties.

(2) Amounts are included in Other Assets in the Consolidated Balance Sheets.

(3) Natural gas derivatives include no material amounts related to physical forward transactions with Enable.

The following table presents additional information about assets or liabilities, including derivatives that are measured at fair value on a recurring basis for which CERC has utilized Level 3 inputs to determine fair value:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Derivative assets and liabilities, net		
	Year Ended December 31,		
	2016	2015	2014
	(in millions)		
Beginning balance	$ 12	$ 17	$ 3
Purchases	12	—	—
Total gains	12	7	14
Total settlements	(27)	(12)	1
Transfers out of Level 3	(1)	(1)	—
Transfers into Level 3	5	1	(1)
Ending balance (1)	$ 13	$ 12	$ 17
The amount of total gains for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at the reporting date	$ 11	$ 6	$ 16

(1) During 2016, 2015 and 2014, CERC did not have significant Level 3 sales.

Items Measured at Fair Value on a Nonrecurring Basis

In 2015, CERC determined that an other than temporary decrease in the value of its investment in Enable had occurred and, using multiple valuation methodologies under both the market and income approaches, recorded an impairment on its investment in Enable of $1,225 million. Key assumptions in the market approach included recent market transactions of comparable companies and EBITDA to total enterprise multiples for comparable companies. Due to volatility of the quoted price of Enable’s units at the valuation date, a volume weighted average price was used under the market approach to best approximate fair value at the measurement date. Key assumptions in the income approach included Enable’s forecasted cash distributions, projected cash flows of incentive distribution rights, forecasted growth rate of Enable’s cash distributions beyond 2020, and the discount rate used to determine the present value of the estimated future cash flows. A weighing of the different approaches was utilized to determine the estimated fair value of our investment in Enable. Based on the significant unobservable estimates and assumptions required, CERC concluded that the fair value estimate should be classified as a Level 3 measurement within the fair value hierarchy. See Note 11 for further discussion of the impairments. As of December 31, 2016, there were no significant assets or liabilities measured at fair value on a nonrecurring basis.

Estimated Fair Value of Financial Instruments

The fair values of cash and cash equivalents and short-term borrowings are estimated to be approximately equivalent to carrying amounts and have been excluded from the table below. The carrying amounts of non-trading derivative assets and liabilities are stated at fair value and are excluded from the table below. The fair value of each debt instrument is determined by multiplying the principal amount of each debt instrument by the market price. These assets and liabilities, which are not measured at fair value in the Consolidated Balance Sheets but for which the fair value is disclosed, would be classified as Level 1 or Level 2 in the fair value hierarchy.

	December 31, 2016		December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Financial assets:				
Notes receivable - affiliated companies	$ —	$ —	$ 363	$ 356
Financial liabilities:				
Long-term debt	$ 2,375	$ 2,551	$ 2,341	$ 2,539

(11) Unconsolidated Affiliates

CERC has the ability to significantly influence the operating and financial policies of Enable, a publicly traded MLP, and, accordingly, accounts for its investment in Enable's common and subordinated units using the equity method of accounting. See Note 2 for information on the formation of Enable.

CERC's maximum exposure to loss related to Enable, a VIE in which CERC is not the primary beneficiary, is limited to its equity investment as presented in the Consolidated Balance Sheet as of December 31, 2016 and outstanding current accounts receivable from Enable. In connection with CenterPoint Energy's purchase of Series A Preferred Units from Enable, Enable redeemed $363 million of notes owed to a wholly-owned subsidiary of CERC Corp., which bore interest at an annual rate of 2.10% to 2.45%.

Effective on the Formation Date, CenterPoint Energy and Enable entered into the Transition Agreements. Under the Services Agreement, CERC agreed to provide certain support services to Enable such as accounting, legal, risk management and treasury functions for an initial term, which ended on April 30, 2016. CERC is providing certain services to Enable on a year-to-year basis. Enable may terminate (i) the entire Services Agreement with at least 90 days' notice prior to the end of any extension term, or (ii) either any service provided under the Services Agreement, or the entire Services Agreement, at any time upon approval by its board of directors and with at least 180 days' notice.

CERC provided seconded employees to Enable to support its operations for a term ending on December 31, 2014. Enable, at its discretion, had the right to select and offer employment to seconded employees from CERC. During the fourth quarter of 2014, Enable notified CERC that it selected seconded employees and provided employment offers to substantially all of the seconded employees from CERC. Substantially all of the seconded employees became employees of Enable effective January 1, 2015.

In accordance with the Enable formation agreements, CERC had certain put rights, and Enable had certain call rights, exercisable with respect to the 25.05% interest in SESH retained by CenterPoint Energy. As of June 30, 2015, CERC's remaining interest in SESH was transferred to Enable.

Transactions with Enable:

	Year Ended December 31,		
	2016	2015	2014
	(in millions)		
Reimbursement of transition services (1)	$ 7	$ 16	$ 163
Natural gas expenses, including transportation and storage costs	110	117	130
Interest income related to notes receivable from Enable	1	8	8

(1) Represents amounts billed under the Transition Agreements, including the costs of seconded employees. Actual transition services costs are recorded net of reimbursement.

	Year Ended December 31,	
	2016	2015
	(in millions)	
Accounts receivable for amounts billed for transition services	$ 1	$ 3
Interest receivable related to notes receivable from Enable	—	4
Accounts payable for natural gas purchases from Enable	10	11

CERC evaluates its equity method investments for impairment when factors indicate that a decrease in the value of its investment has occurred and the carrying amount of its investment may not be recoverable. An impairment loss, based on the excess of the carrying value over estimated fair value of the investment, is recognized in earnings when an impairment is deemed to be other than temporary. Considerable judgment is used in determining if an impairment loss is other than temporary and the amount of any impairment. Based on the sustained low Enable common unit price and further declines in such price during the year ended December 31, 2015, as well as the market outlook for continued depressed crude oil and natural gas prices impacting the midstream oil and gas industry, CERC determined that an other than temporary decrease in the value of its equity method investment in Enable had occurred. CERC wrote down the value of its equity method investment in Enable to its estimated fair value which resulted in impairment charges of $1,225 million for the year ended December 31, 2015. Both the income approach and market approach were utilized to estimate the fair value of CERC's total investment in Enable, which includes the limited partner common and subordinated units, general partner interest and incentive distribution rights held by CERC. The determination of fair value considered a number of relevant factors including Enable's common unit price and forecasted results, recent comparable transactions and the limited float of Enable's publicly traded common units. See Note 10 for further discussion of the determination of fair value of CERC's equity method investment in Enable in 2015.

As of December 31, 2016, the carrying value of CERC's equity method investment in Enable was $10.71 per unit, which includes limited partner common and subordinated units, a general partner interest and incentive distribution rights. On December 31, 2016, Enable's common unit price closed at $15.73. There was no impairment indicated in 2016.

Investment in Unconsolidated Affiliates:

	As of December 31,	
	2016	2015
	(in millions)	
Enable	$ 2,505	$ 2,594

Equity in Earnings (Losses) of Unconsolidated Affiliates, net:

	Year Ended December 31,		
	2016	2015	2014
	(in millions)		
Enable	$ 208	$ (1,633)	$ 303
SESH (1)	—	—	5
Total	$ 208	$ (1,633)	$ 308

(1) CERC contributed a 24.95% interest in SESH to Enable on May 30, 2014 and its remaining 0.1% interest in SESH to Enable on June 30, 2015.

Limited Partner Interest in Enable:

	As of December 31,		
	2016	2015	2014
CenterPoint Energy	54.1% (1)	55.4%	55.4%
OGE	25.7%	26.3%	26.3%

(1) In November 2016, Enable closed a public offering of 10,000,000 common units. In connection with the offering, Enable and an affiliate of ArcLight sold an additional combined 1,500,000 common units to the underwriters.

Enable Common and Subordinated Units Held:

	December 31, 2016	
	Common	Subordinated
CenterPoint Energy	94,151,707	139,704,916
OGE	42,832,291	68,150,514

Sales of more than 5% of the aggregate of the common units and subordinated units we own in Enable or sales by OGE of more than 5% of the aggregate of the common units and subordinated units it owns in Enable are subject to mutual rights of first offer and first refusal.

Enable is controlled jointly by CERC Corp. and OGE, and each own 50% of the management rights in the general partner of Enable. Sale of our or OGE's ownership interests in Enable's general partner to a third party is subject to mutual rights of first offer and first refusal, and we are not permitted to dispose of less than all of our interest in Enable's general partner.

Summarized consolidated income (loss) information for Enable is as follows:

	Year Ended December 31,		
	2016	2015	2014
		(in millions)	
Operating revenues	$ 2,272	$ 2,418	$ 3,367
Cost of sales, excluding depreciation and amortization	1,017	1,097	1,914
Impairment of goodwill and other long-lived assets	9	1,134	8
Operating income (loss)	385	(712)	586
Net income (loss) attributable to Enable	290	(752)	530
Reconciliation of Equity in Earnings (Losses), net:			
CERC's interest	$ 160	$ (416)	$ 298
Basis difference amortization (1)	48	8	5
Impairment of CERC's equity method investment in Enable	—	(1,225)	—
CERC's equity in earnings (losses), net (2)	$ 208	$ (1,633)	$ 303

(1) Equity in earnings of unconsolidated affiliates includes CERC's share of Enable earnings adjusted for the amortization of the basis difference of CERC's original investment in Enable and its underlying equity in net assets of Enable. The basis difference is being amortized over approximately 33 years, the average life of the assets to which the basis difference is attributed.

(2) These amounts include impairment charges totaling $1,846 million composed of CERC's impairment of its equity method investment in Enable of $1,225 million and CERC's share, $621 million, of impairment charges Enable recorded for goodwill and long-lived assets for the year ended December 31, 2015. This impairment is offset by $213 million of earnings for the year ended December 31, 2015.

Summarized consolidated balance sheet information for Enable is as follows:

	December 31,	
	2016	2015
	(in millions)	
Current assets	$ 396	$ 381
Non-current assets	10,816	10,845
Current liabilities	362	615
Non-current liabilities	3,056	3,080
Non-controlling interest	12	12
Preferred equity	362	—
Enable partners’ capital	7,420	7,519
Reconciliation of Investment in Enable:		
CERC’s ownership interest in Enable partners’ capital	$ 4,067	$ 4,163
CERC’s basis difference	(1,562)	(1,569)
CERC’s investment in Enable	$ 2,505	$ 2,594

Distributions Received from Unconsolidated Affiliates:

	Year Ended December 31,		
	2016	2015	2014
	(in millions)		
Investment in Enable’s common and subordinated units	$ 297	$ 294	$ 298
Interest in SESH (1)	—	—	7
Total	$ 297	$ 294	$ 305

(1) CERC contributed a 24.95% interest in SESH to Enable on May 30, 2014 and its remaining 0.1% interest in SESH to Enable on June 30, 2015.

As of December 31, 2016, CERC Corp. and OGE also own 40% and 60%, respectively, of the incentive distribution rights held by the general partner of Enable. Enable is expected to pay a minimum quarterly distribution of $0.2875 per unit on its outstanding units to the extent it has sufficient cash from operations after establishment of cash reserves and payment of fees and expenses, including payments to its general partner and its affiliates, within 60 days after the end of each quarter. If cash distributions to Enable’s unitholders exceed $0.330625 per unit in any quarter, the general partner will receive increasing percentages or incentive distributions rights, up to 50%, of the cash Enable distributes in excess of that amount. In certain circumstances the general partner of Enable will have the right to reset the minimum quarterly distribution and the target distribution levels at which the incentive distributions receive increasing percentages to higher levels based on Enable’s cash distributions at the time of the exercise of this reset election. To date, no incentive distributions have been made.

(12) Short-term Borrowings and Long-term Debt

	December 31, 2016		December 31, 2015	
	Long-Term	Current (1)	Long-Term (2)	Current (1)
	(in millions)			
Short-term borrowings:				
Inventory financing (3)	$ —	$ 35	$ —	$ 40
Total short-term borrowings	—	35	—	40
Long-term debt:				
Senior notes 4.50% to 6.625% due 2017 to 2041	1,593	250	1,843	325
Commercial paper (4)	569	—	219	—
Unamortized debt issuance costs	(10)	—	(12)	—
Unamortized discount and premium	(27)	—	(34)	—
Total long-term debt	2,125	250	2,016	325
Total debt	$ 2,125	$ 285	$ 2,016	$ 365

(1) Includes amounts due or exchangeable within one year of the date noted.

(2) Includes $12 million of unamortized debt issuance costs to reflect adoption of ASU 2015-03.

(3) NGD currently has AMAs associated with its utility distribution service in Arkansas, north Louisiana and Oklahoma that extend through 2020. Pursuant to the provisions of the agreements, NGD sells natural gas and agrees to repurchase an equivalent amount of natural gas during the winter heating seasons at the same cost, plus a financing charge. These transactions are accounted for as an inventory financing.

(4) Classified as long-term debt because the termination date of the facility that backstops the commercial paper is more than one year from the date noted.

CERC's short-term borrowings from the money pool are not reflected in the table above. For information regarding CERC's money pool borrowings, please see Note 8.

Long-term Debt

Debt Retirements. In May 2016, CERC retired approximately $325 million aggregate principal amount of its 6.15% senior notes at their maturity. The retirement of senior notes was financed by the issuance of commercial paper.

Revolving Credit Facility. As of December 31, 2016 and 2015, CERC had the following revolving credit facility and utilization of such facility:

	December 31, 2016			December 31, 2015		
Size of Facility	Loans	Letters of Credit	Commercial Paper	Loans	Letters of Credit	Commercial Paper
			(in millions)			
$ 600	$ —	$ 4	$ 569 (1)	$ —	$ 2	$ 219 (1)

(1) Weighted average interest rate was approximately 1.03% and 0.81% as of December 31, 2016 and 2015, respectively.

Execution Date	Size of Facility	Draw Rate of LIBOR plus (1)	Financial Covenant Limit on Debt to Capital Ratio	Debt to Capital Ratio as of December 31, 2016	Termination Date
	(in millions)				
March 3, 2016	$ 600	1.25%	65%	35.8%	March 3, 2021

(1) Based on current credit ratings.

CERC Corp. was in compliance with all financial covenants in its revolving credit facility as of December 31, 2016.

Maturities. CERC Corp. has the following long-term debt maturities:

		(in millions)
2017	$	250
2018		300
2019		—
2020		—
2021		1,162

(13) Income Taxes

The components of CERC's income tax expense (benefit) were as follows:

	Year Ended December 31,		
	2016	2015	2014
		(in millions)	
Current income tax expense:			
State	$ 6	$ 3	$ 10
Total current expense	6	3	10
Deferred income tax expense (benefit):			
Federal	130	(488)	171
State	26	(54)	7
Total deferred expense (benefit)	156	(542)	178
Total income tax expense (benefit)	$ 162	$ (539)	$ 188

A reconciliation of income tax expense (benefit) using the federal statutory income tax rate to the actual income tax expense and resulting effective income tax rate is as follows:

	Year Ended December 31,		
	2016	2015	2014
		(in millions)	
Income (loss) before income taxes	$ 407	$ (1,451)	$ 511
Federal statutory income tax rate	35%	35%	35%
Expected federal income tax expense (benefit)	142	(508)	179
Increase (decrease) in tax expense resulting from:			
State income tax expense, net of federal income tax	17	(33)	11
State valuation allowance, net of federal income tax	3	—	—
Other, net	—	2	(2)
Total	20	(31)	9
Total income tax expense (benefit)	$ 162	$ (539)	$ 188
Effective tax rate	40%	37%	37%

The tax effects of temporary differences that give rise to significant portions of deferred tax assets and liabilities were as follows:

	December 31,	
	2016	2015
	(in millions)	
Deferred tax assets:		
Benefits and compensation	$ 45	$ 39
Loss and credit carryforwards	451	388
AROs	64	59
Other	18	39
Valuation allowance	(5)	(2)
Total deferred tax assets	573	523
Deferred tax liabilities:		
Property, plant, and equipment	1,017	929
Investment in unconsolidated affiliates	1,383	1,277
Regulatory assets/liabilities, net	8	—
Other	90	91
Total deferred tax liabilities	2,498	2,297
Net deferred tax liabilities	$ 1,925	$ 1,774

CERC is a member of the U.S. federal consolidated income tax return of CenterPoint Energy. CERC reports its income tax provision on a separate entity basis pursuant to a tax sharing agreement with CenterPoint Energy.

Tax Attribute Carryforwards and Valuation Allowance. CERC has $1.1 billion of federal net operating loss carryforwards that begin to expire in 2031. CERC has $958 million of state net operating loss carryforwards that expire between 2017 and 2036, $11 million of state tax credits that do not expire and $244 million of state capital loss carryforwards that expire in 2017. CERC reported a tax-effected valuation allowance of $5 million because it is more likely than not that the benefit from certain state carryforwards will not be realized.

Uncertain Income Tax Positions. CERC reported no uncertain tax liability as of December 31, 2016, 2015 and 2014. We expect no significant change to the uncertain tax liability over the next twelve months ending December 31, 2017.

Tax Audits and Settlements. Tax years through 2014 have been audited and settled with the IRS. For the 2015, 2016 and 2017 tax years, CenterPoint Energy is a participant in the IRS's Compliance Assurance Process.

(14) Commitments and Contingencies

(a) Natural Gas Supply Commitments

Natural gas supply commitments include natural gas contracts related to CERC's Natural Gas Distribution and Energy Services business segments, which have various quantity requirements and durations, that are not classified as non-trading derivative assets and liabilities in CERC's Consolidated Balance Sheets as of December 31, 2016 and 2015 as these contracts meet an exception as "normal purchases contracts" or do not meet the definition of a derivative. Natural gas supply commitments also include natural gas transportation contracts that do not meet the definition of a derivative. As of December 31, 2016, minimum payment obligations for natural gas supply commitments are approximately:

	(in millions)
2017	$ 461
2018	467
2019	268
2020	125
2021	127
2022 and beyond	8

(b) AMAs

NGD has had AMAs associated with its utility distribution service in Arkansas, Louisiana, Mississippi, Oklahoma and Texas. Generally, AMAs are contracts between NGD and an asset manager that are intended to transfer the working capital obligation and maximize the utilization of the assets. In these AMAs, NGD agrees to release transportation and storage capacity to other parties to manage natural gas storage, supply and delivery arrangements for NGD and to use the released capacity for other purposes when it is not needed for NGD. NGD is compensated by the asset manager through payments made over the life of the AMAs based in part on the results of the asset optimization. NGD has an obligation to purchase its winter storage requirements that have been released to the asset manager under these AMAs. NGD has received approval from the state regulatory commissions in Arkansas, Louisiana, Mississippi and Oklahoma to retain a share of the AMA proceeds. NGD currently has AMAs in Arkansas, north Louisiana and Oklahoma that extend through 2020.

(c) Lease Commitments

The following table sets forth information concerning CERC's obligations under non-cancelable long-term operating leases as of December 31, 2016, which primarily consist of rental agreements for building space, data processing equipment, compression equipment and rights-of-way:

		(in millions)
2017	$	5
2018		4
2019		4
2020		3
2021		2
2022 and beyond		7
Total	$	25

Total lease expense for all operating leases was $9 million, $8 million and $9 million during 2016, 2015 and 2014, respectively.

(d) Legal, Environmental and Other Matters

Legal Matters

Gas Market Manipulation Cases. CenterPoint Energy, Houston Electric or their predecessor, Reliant Energy, and certain of their former subsidiaries have been named as defendants in certain lawsuits described below. Under a master separation agreement between CenterPoint Energy and a former subsidiary, RRI, CenterPoint Energy and its subsidiaries are entitled to be indemnified by RRI and its successors for any losses, including certain attorneys' fees and other costs, arising out of these lawsuits. In May 2009, RRI sold its Texas retail business to a subsidiary of NRG and RRI changed its name to RRI Energy, Inc. In December 2010, Mirant Corporation merged with and became a wholly-owned subsidiary of RRI, and RRI changed its name to GenOn. In December 2012, NRG acquired GenOn through a merger in which GenOn became a wholly-owned subsidiary of NRG. None of the sale of the retail business, the merger with Mirant Corporation, or the acquisition of GenOn by NRG alters RRI's (now GenOn's) contractual obligations to indemnify CenterPoint Energy and its subsidiaries, including Houston Electric, for certain liabilities, including their indemnification obligations regarding the gas market manipulation litigation.

A large number of lawsuits were filed against numerous gas market participants in a number of federal and western state courts in connection with the operation of the natural gas markets in 2000–2002. CenterPoint Energy and its affiliates have since been released or dismissed from all such cases. CES, a subsidiary of CERC Corp., was a defendant in a case now pending in federal court in Nevada alleging a conspiracy to inflate Wisconsin natural gas prices in 2000–2002. On May 24, 2016, the district court granted CES's motion for summary judgment, dismissing CES from the case. The plaintiffs have appealed that ruling. CenterPoint Energy and CES intend to continue vigorously defending against the plaintiffs' claims. CERC does not expect the ultimate outcome of this matter to have a material adverse effect on its financial condition, results of operations or cash flows.

Environmental Matters

MGP Sites. CERC and its predecessors operated MGPs in the past. With respect to certain Minnesota MGP sites, CERC has completed state-ordered remediation and continues state-ordered monitoring and water treatment. As of December 31, 2016, CERC had a recorded liability of $7 million for continued monitoring and any future remediation required by regulators in Minnesota. The estimated range of possible remediation costs for the sites for which CERC believes it may have responsibility was $5 million to $30 million based on remediation continuing for 30 to 50 years. The cost estimates are based on studies of a site or industry average costs for remediation of sites of similar size. The actual remediation costs will depend on the number of sites to be remediated, the participation of other PRPs, if any, and the remediation methods used.

In addition to the Minnesota sites, the EPA and other regulators have investigated MGP sites that were owned or operated by CERC or may have been owned by one of its former affiliates. CERC does not expect the ultimate outcome of these matters to have a material adverse effect on its financial condition, results of operations or cash flows.

Asbestos. Some facilities owned by CERC or its predecessors contain or have contained asbestos insulation and other asbestos-containing materials. CERC and its predecessor companies are from time to time named, along with numerous others, as defendants in lawsuits filed by a number of individuals who claim injury due to exposure to asbestos, and CERC anticipates that additional claims may be asserted in the future. Although their ultimate outcome cannot be predicted at this time, CERC does not expect these matters, either individually or in the aggregate, to have a material adverse effect on its financial condition, results of operations or cash flows.

Other Environmental. From time to time, CERC identifies the presence of environmental contaminants during its operations or on property where its predecessor companies have conducted operations. Other such sites involving contaminants may be identified in the future. CERC has and expects to continue to remediate identified sites consistent with its legal obligations. From time to time, CERC has received notices from regulatory authorities or others regarding its status as a PRP in connection with sites found to require remediation due to the presence of environmental contaminants. In addition, CERC has been named from time to time as a defendant in litigation related to such sites. Although the ultimate outcome of such matters cannot be predicted at this time, CERC does not expect these matters, either individually or in the aggregate, to have a material adverse effect on its financial condition, results of operations or cash flows.

Other Proceedings

CERC is involved in other legal, environmental, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business. From time to time, CERC is also a defendant in legal proceedings with respect to claims brought by various plaintiffs against broad groups of participants in the energy industry. Some of these proceedings involve substantial amounts. CERC regularly analyzes current information and, as necessary, provides accruals for probable and reasonably estimable liabilities on the eventual disposition of these matters. CERC does not expect the disposition of these matters to have a material adverse effect on its financial condition, results of operations or cash flows.

(15) Unaudited Quarterly Information

Summarized quarterly financial data is as follows:

	Year Ended December 31, 2016			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in millions)			
Revenues	$ 1,320	$ 807	$ 978	$ 1,349
Operating income	166	18	26	108
Net income	120	6	43	76

	Year Ended December 31, 2015			
	First Quarter	Second Quarter	Third Quarter (1)	Fourth Quarter (2)
	(in millions)			
Revenues	$ 1,817	$ 824	$ 799	$ 1,087
Operating income	160	27	18	108
Net income (loss)	109	22	(508)	(535)

(1) CERC recognized $862 million ($537 million after tax) in impairment charges related to Enable during the three months ended September 30, 2015.

(2) CERC recognized $984 million ($620 million after tax) in impairment charges related to Enable during the three months ended December 31, 2015.

(16) Reportable Business Segments

CERC's determination of reportable business segments considers the strategic operating units under which it manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments. CERC uses operating income as the measure of profit or loss for its business segments other than Midstream Investments, where it uses equity in earnings.

CERC's reportable business segments include the following: Natural Gas Distribution, Energy Services, Midstream Investments and Other Operations. Natural Gas Distribution consists of intrastate natural gas sales to, and natural gas transportation and distribution for, residential, commercial, industrial and institutional customers. Energy Services represents CERC's non-rate regulated gas sales and services operations. Midstream Investments consists of CERC's equity investment in Enable. The Other Operations business segment includes unallocated corporate costs and inter-segment eliminations.

Long-lived assets include net property, plant and equipment, goodwill and other intangibles and equity investments in unconsolidated subsidiaries. Intersegment sales are eliminated in consolidation.

Financial data for business segments and products and services are as follows:

	Revenues from External Customers	Intersegment Revenues	Depreciation and Amortization	Operating Income (Loss)	Total Assets (1)	Expenditures for Long-Lived Assets
			(in millions)			
As of and for the year ended December 31, 2016:						
Natural Gas Distribution	$ 2,380	$ 29	$ 242	$ 303	$ 6,099	$ 510
Energy Services	2,073	26	7	20	1,102	5
Midstream Investments (2)	—	—	—	—	2,505	—
Other	1	—	—	(5)	75	—
Reconciling Eliminations	—	(55)	—	—	(563)	—
Consolidated	$ 4,454	$ —	$ 249	$ 318	$ 9,218	$ 515
As of and for the year ended December 31, 2015:						
Natural Gas Distribution	$ 2,603	$ 29	$ 222	$ 273	$ 5,657	$ 601
Energy Services	1,924	33	5	42	857	5
Midstream Investments (2)	—	—	—	—	2,594	—
Other	—	—	—	(2)	777	—
Reconciling Eliminations	—	(62)	—	—	(744)	—
Consolidated	$ 4,527	$ —	$ 227	$ 313	$ 9,141	$ 606
As of and for the year ended December 31, 2014:						
Natural Gas Distribution	$ 3,271	$ 30	$ 201	$ 287	$ 5,464	$ 525
Energy Services	3,095	84	5	52	978	3
Midstream Investments (2)	—	—	—	—	4,521	—
Other	1	—	—	(4)	1,031	—
Reconciling Eliminations	—	(114)	—	—	(964)	—
Consolidated	$ 6,367	$ —	$ 206	$ 335	$ 11,030	$ 528

(1) Amounts for 2015 and 2014 have been restated to reflect the adoption of ASU 2015-03.

(2) Midstream Investments’ equity earnings (losses) are as follows:

	Year Ended December 31,		
	2016	2015	2014
	(in millions)		
Enable (a)	$ 208	$ (1,633)	$ 303
SESH	—	—	5
Total	$ 208	$ (1,633)	$ 308

(a) These amounts include impairment charges totaling $1,846 million composed of CERC’s impairment of its equity method investment in Enable of $1,225 million and CERC’s share, $621 million, of impairment charges Enable recorded for goodwill and long-lived assets for the year ended December 31, 2015. This impairment is offset by $213 million of earnings for the year ended December 31, 2015.

	Year Ended December 31,		
Revenues by Products and Services:	2016	2015	2014
	(in millions)		
Retail gas sales	$ 3,329	$ 3,725	$ 5,049
Wholesale gas sales	977	657	1,159
Gas transportation and processing	23	26	38
Energy products and services	125	119	121
Total	$ 4,454	$ 4,527	$ 6,367

(17) Subsequent Events

On January 3, 2017, CES closed the previously announced agreement to acquire AEM for approximately $140 million, including estimated working capital of $100 million. With the addition of this business, CES now operates in a total of 33 states, including seven states where CES previously had no commercial or industrial natural gas sales customers though CES did have other operations in five of those states. CES has begun to integrate AEM into its existing business. Due to the limited amount of time since the acquisition, the initial accounting for the acquisition is incomplete, principally with regard to the valuation of derivatives, property, plant and equipment, intangible assets and goodwill. CERC intends to provide additional business combination disclosures, if material, in its Form 10-Q for the first quarter of 2017.

On February 10, 2017, Enable declared a quarterly cash distribution of $0.318 per unit on all of its outstanding common and subordinated units for the quarter ended December 31, 2016. Accordingly, CERC Corp. expects to receive a cash distribution of approximately $74 million from Enable in the first quarter of 2017 to be made with respect to CERC Corp.’s limited partner interest in Enable for the fourth quarter of 2016.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

Disclosure Controls and Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2016 to provide assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding disclosure.

There has been no change in our internal controls over financial reporting that occurred during the three months ended December 31, 2016 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rule 13a-15(f) or 15d-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;

- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and

- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Management has designed its internal control over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with accounting principles generally accepted in the United States of America. Management's assessment included review and testing of both the design effectiveness and operating effectiveness of controls over all relevant assertions related to all significant accounts and disclosures in the financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control — Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control — Integrated Framework* (2013), our management has concluded that our internal control over financial reporting was effective as of December 31, 2016.

This annual report does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by our independent registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit us to provide only management's report in this annual report.

Item 9B. ***Other Information***

The ratio of earnings to fixed charges as calculated pursuant to Securities and Exchange Commission rules was 4.89, 4.34, 4.50, 3.34 and 3.05 for the years ended December 31, 2016, 2015, 2014, 2013 and 2012, respectively.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information called for by Item 10 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly-Owned Subsidiaries).

Item 11. ***Executive Compensation***

The information called for by Item 11 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly-Owned Subsidiaries).

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The information called for by Item 12 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly-Owned Subsidiaries).

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

The information called for by Item 13 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly-Owned Subsidiaries).

Item 14. ***Principal Accounting Fees and Services***

Aggregate fees billed to CERC during the fiscal years ending December 31, 2016 and 2015 by its principal accounting firm, Deloitte & Touche LLP, are set forth below.

	Year Ended December 31,	
	2016	**2015**
Audit fees (1)	$ 1,263,520	$ 1,176,480
Audit-related fees (2)	86,075	61,073
Total audit and audit-related fees	1,349,595	1,237,553
Tax fees	—	—
All other fees	—	—
Total fees	$ 1,349,595	$ 1,237,553

(1) For 2016 and 2015, amounts include fees for services provided by the principal accounting firm relating to the integrated audit of financial statements and internal control over financial reporting, statutory audits, attest services, and regulatory filings.

(2) For 2016 and 2015, includes fees for consultations concerning financial accounting and reporting standards and various agreed-upon or expanded procedures related to accounting records to comply with financial accounting or regulatory reporting matters.

CERC is not required to have, and does not have, an audit committee.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a)(1) Financial Statements.

The financial statements of Enable Midstream Partners, LP required pursuant to Rule 3-09 of Regulation S-X are included in this filing as Exhibit 99.1.

(a)(2) Financial Statement Schedules for the Three Years Ended December 31, 2016.

The following schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the financial statements:

I, II, III, IV and V.

(a)(3) Exhibits.

See Index of Exhibits beginning on page 92.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, the State of Texas, on the 28th day of February, 2017.

CENTERPOINT ENERGY RESOURCES CORP.
(Registrant)

By: /s/ SCOTT M. PROCHAZKA
Scott M. Prochazka
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 28, 2017.

Signature	Title
/s/ SCOTT M. PROCHAZKA (Scott M. Prochazka)	Chairman, President and Chief Executive Officer (Principal Executive Officer and Director)
/s/ WILLIAM D. ROGERS (William D. Rogers)	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ KRISTIE L. COLVIN (Kristie L. Colvin)	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES

EXHIBITS TO THE ANNUAL REPORT ON FORM 10-K
For Fiscal Year Ended December 31, 2016

INDEX OF EXHIBITS

Exhibits not incorporated by reference to a prior filing are designated by a cross (+); all exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
2(a)(1)	Agreement and Plan of Merger among CERC, Houston Lighting and Power Company (“HL&P”), HI Merger, Inc. and NorAm Energy Corp. (“NorAm”) dated August 11, 1996	Houston Industries’ (“HI’s”) Form 8-K dated August 11, 1996	1-7629	2
2(a)(2)	Amendment to Agreement and Plan of Merger among CERC, HL&P, HI Merger, Inc. and NorAm dated August 11, 1996	Registration Statement on Form S-4	333-11329	2(c)
2(b)	Agreement and Plan of Merger dated December 29, 2000 merging Reliant Resources Merger Sub, Inc. with and into Reliant Energy Services, Inc.	Registration Statement on Form S-3	333-54526	2
2(c)	Master Formation Agreement dated March 14, 2013 by and among CenterPoint Energy, Inc., OGE Energy Corp., Bronco Midstream Holdings, LLC and Bronco Midstream Holdings II, LLC.	Form 8-K dated March 14, 2013	1-31447	2.1
3(a)(1)	Certificate of Incorporation of Reliant Energy Resources Corp. (“RERC Corp.”)	Form 10-K for the year ended December 31, 1997	1-3187	3(a)(1)
3(a)(2)	Certificate of Merger merging former NorAm Energy Corp. with and into HI Merger, Inc. dated August 6, 1997	Form 10-K for the year ended December 31, 1997	1-3187	3(a)(2)
3(a)(3)	Certificate of Amendment changing the name to Reliant Energy Resources Corp.	Form 10-K for the year ended December 31, 1998	1-3187	3(a)(3)
3(a)(4)	Certificate of Amendment changing the name to CenterPoint Energy Resources Corp.	Form 10-Q for the quarter ended June 30, 2003	1-13265	3(a)(4)
3(b)	Bylaws of RERC Corp.	Form 10-K for the year ended December 31, 1997	1-3187	3(b)
4(a)(1)	Indenture, dated as of February 1, 1998, between RERC Corp. and Chase Bank of Texas, National Association, as Trustee	Form 8-K dated February 5, 1998	1-13265	4.1
4(a)(2)	Supplemental Indenture No. 1, dated as of February 1, 1998, providing for the issuance of RERC Corp.’s 6 1/2% Debentures due February 1, 2008	Form 8-K dated February 5, 1998	1-13265	4.2
4(a)(3)	Supplemental Indenture No. 2, dated as of November 1, 1998, providing for the issuance of RERC Corp.’s 6 3/8% Term Enhanced ReMarketable Securities	Form 8-K dated November 9, 1998	1-13265	4.1
4(a)(4)	Supplemental Indenture No. 3, dated as of July 1, 2000, providing for the issuance of RERC Corp.’s 8.125% Notes due 2005	Registration Statement on Form S-4	333-49162	4.2

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(a)(5)	Supplemental Indenture No. 4, dated as of February 15, 2001, providing for the issuance of RERC Corp.'s 7.75% Notes due 2011	Form 8-K dated February 21, 2001	1-13265	4.1
4(a)(6)	Supplemental Indenture No. 5, dated as of March 25, 2003, providing for the issuance of CERC Corp.'s 7.875% Senior Notes due 2013	Form 8-K dated March 18, 2003	1-13265	4.1
4(a)(7)	Supplemental Indenture No. 6, dated as of April 14, 2003, providing for the issuance of CERC Corp.'s 7.875% Senior Notes due 2013	Form 8-K dated April 7, 2003	1-13265	4.2
4(a)(8)	Supplemental Indenture No. 7, dated as of November 3, 2003, providing for the issuance of CERC Corp.'s 5.95% Senior Notes due 2014	Form 8-K dated October 29, 2003	1-13265	4.2
4(a)(9)	Supplemental Indenture No. 8, dated as of December 28, 2005, providing for the issuance of CERC Corp.'s 6 1/2% Debentures due 2008	CenterPoint Energy, Inc.'s ("CNP's") Form 10-K for the year ended December 31, 2005	1-31447	4(f)(9)
4(a)(10)	Supplemental Indenture No. 9, dated as of May 18, 2006, providing for the issuance of CERC Corp.'s 6.15% Senior Notes due 2016	CNP's Form 10-Q for the quarter ended June 30, 2006	1-31447	4.7
4(a)(11)	Supplemental Indenture No. 10, dated as of February 6, 2007, providing for the issuance of CERC Corp.'s 6.25% Senior Notes due 2037	CNP's Form 10-K for the year ended December 31, 2007	1-31447	4(f)(11)
4(a)(12)	Supplemental Indenture No. 11 dated as of October 23, 2007, providing for the issuance of CERC Corp.'s 6.125% Senior Notes due 2017	CNP's Form 10-Q for quarter ended September 30, 2007	1-31447	4.8
4(a)(13)	Supplemental Indenture No. 12 dated as of October 23, 2007, providing for the issuance of CERC Corp.'s 6.625% Senior Notes due 2037	CNP's Form 10-Q for quarter ended September 30, 2007	1-31447	4.9
4(a)(14)	Supplemental Indenture No. 13 dated as of May 15, 2008, providing for the issuance of CERC Corp.'s 6.00% Senior Notes due 2018	CNP's Form 10-Q for quarter ended June 30, 2008	1-31447	4.9
4(a)(15)	Supplemental Indenture No. 14 to Exhibit 4(a)(1) dated as of January 11, 2011, providing for the issuance of CERC Corp.'s 4.50% Senior Notes due 2021 and 5.85% Senior Notes due 2041	CNP's Form 10-K for the year ended December 31, 2010	1-31447	4(a)(15)
4(a)(16)	Supplemental Indenture No. 15 to Exhibit 4(a)(1) dated as of January 20, 2011, providing for the issuance of CERC Corp.'s 4.50% Senior Notes due 2021	CNP's Form 10-K for the year ended December 31, 2010	1-31447	4(a)(16)
4(b)(1)	$600,000,000 Credit Agreement dated as of March 3, 2016, among CERC Corp., as Borrower, and the banks named therein	CNP's Form 8-K dated March 3, 2016	1-31447	4.3

There have not been filed as exhibits to this Form 10-K certain long-term debt instruments, including indentures, under which the total amount of securities do not exceed 10% of the total assets of CERC. CERC hereby agrees to furnish a copy of any such instrument to the SEC upon request.

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
10(a)	Service Agreement by and between Mississippi River Transmission Corporation and Laclede Gas Company dated August 22, 1989	NorAm's Form 10-K for the year ended December 31, 1989	1-13265	10.20
10(b)	Commitment Letter dated March 14, 2013 by and among CenterPoint Energy, Inc., Enogex LLC, Citigroup Global Markets Inc., UBS Loan Finance LLC and UBS Securities LLC relating to a $1,050,000,000 3-year unsecured term loan facility.	Form 8-K dated March 14, 2013	1-31447	10.1
10(c)	Commitment Letter dated March 14, 2013 by and among CenterPoint Energy, Inc., Enogex LLC, Citigroup Global Markets Inc., UBS Loan Finance LLC and UBS Securities LLC relating to a $1,400,000,000 5-year unsecured revolving credit facility.	Form 8-K dated March 14, 2013	1-31447	10.2
10(d)	First Amended and Restated Agreement of Limited Partnership of CenterPoint Energy Field Services LP dated as of May 1, 2013.	Form 8-K dated May 1, 2013	1-31447	10.1
10(e)	First Amendment to the First Amended and Restated Agreement of Limited Partnership of CenterPoint Energy Field Services LP dated as of July 30, 2013.	CNP's Form 10-Q for the quarter ended September 30, 2013	1-31447	10.1
10(f)	Second Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP dated April 16, 2014	CNP's Form 8-K dated April 16, 2014	1-31447	10.1
10(g)	Amended and Restated Limited Liability Company Agreement of CNP OGE GP LLC dated as of May 1, 2013.	CNP's Form 8-K dated May 1, 2013	1-31447	10.2
10(h)	Second Amended and Restated Limited Liability Company Agreement of Enable GP, LLC dated as of July 30, 2013.	CNP's Form 10-Q for the quarter ended September 30, 2013	1-31447	10.2
10(i)	First Amendment to the Second Amended and Restated Limited Liability Company Agreement of Enable GP, LLC dated as of April 16, 2014	CNP's Form 8-K dated April 16, 2014	1-31447	10.2
10(j)	Registration Rights Agreement dated as of May 1, 2013 by and among CenterPoint Energy Field Services LP, CERC Corp., OGE Enogex Holdings LLC, and Enogex Holdings LLC.	CNP's Form 8-K dated May 1, 2013	1-31447	10.3
10(k)	Omnibus Agreement dated as of May 1, 2013 among CenterPoint Energy, Inc., OGE Energy Corp., Enogex Holdings LLC and CenterPoint Energy Field Services LP.	CNP's Form 8-K dated May 1, 2013	1-31447	10.4
10(l)	Term Loan Facility dated as of May 1, 2013 by and among CenterPoint Energy Field Services LP and Citibank, N.A., as administrative agent, UBS Securities LLC, as syndication agent, JPMorgan Chase Bank, N.A. and Wells Fargo Bank, National Association as co-documentation agents, and the several lenders thereto relating to a $1,050,000,000 3-year unsecured term loan facility.	Form 8-K dated May 1, 2013	1-13265	10.5

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
10(m)	First Amendment and Waiver to Term Loan Agreement dated as of January 23, 2014 by and among Enable Midstream Partners, LP, the lenders party thereto and Citibank, N.A., as agent.	CNP's Form 10-K for the year ended December 31, 2013	1-31447	99.4
10(n)	Revolving Credit Agreement dated as of May 1, 2013 by and among CenterPoint Energy Field Services LP and Citibank, N.A., as administrative agent, UBS Securities LLC, as syndication agent, JPMorgan Chase Bank, N.A. and Wells Fargo Bank, National Association, as co-documentation agents, the several lenders from time to time party thereto and the letter of credit issuers from time to time party thereto relating to a $1,400,000,000 5-year unsecured revolving credit facility.	Form 8-K dated May 1, 2013	1-13265	10.6
10(o)	First Amendment and Waiver to Revolving Credit Agreement dated as of January 23, 2014 by and among Enable Midstream Partners, LP, the lenders party thereto and Citibank, N.A., as agent.	CNP's Form 10-K for the year ended December 31, 2013	1-31447	99.3
10(p)	Subordinated Guaranty of Collection dated as of May 1, 2013 by CERC Corp. in favor of Citibank, N.A., as agent.	Form 8-K dated May 1, 2013	1-13265	10.7
10(q)	Indenture, dated as of May 27, 2014, between Enable Midstream Partners, LP and U.S. Bank National Association, as trustee.	Form 8-K dated May 27, 2014	1-13265	10.1
10(r)	First Supplemental Indenture, dated as of May 27, 2014, among Enable Midstream Partners, LP, CenterPoint Energy Resources Corp., as guarantor, and U.S. Bank National Association, as trustee.	Form 8-K dated May 27, 2014	1-13265	10.2
10(s)	Registration Rights Agreement, dated as of May 27, 2014, by and among Enable Midstream Partners, LP, CenterPoint Energy Resources Corp., as guarantor, and RBS Securities Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Credit Suisse Securities (USA) LLC, and RBC Capital Markets, LLC, as representatives of the initial purchasers.	Form 8-K dated May 27, 2014	1-13265	10.3
10(t)(1)	Third Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP dated as of February 18, 2016	Form 8-K dated February 18, 2016	1-13265	10.1
10(t)(2)	Fourth Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP dated June 22, 2016	Form 8-K dated June 22, 2016	1-13265	10.1
10(u)	Third Amended and Restated Limited Liability Company Agreement of Enable GP, LLC dated June 22, 2016	Form 8-K dated June 22, 2016	1-13265	10.2
+12	Computation of Ratios of Earnings to Fixed Charges			
+23.1	Consent of Deloitte & Touche LLP			
+23.2	Consent of Deloitte & Touche LLP, Independent Registered Public Accounting Firm of Enable Midstream Partners, LP			
+31.1	Rule 13a-14(a)/15d-14(a) Certification of Scott M. Prochazka			
+31.2	Rule 13a-14(a)/15d-14(a) Certification of William D. Rogers			
+32.1	Section 1350 Certification of Scott M. Prochazka			

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
+32.2	Section 1350 Certification of William D. Rogers			
99.1	Financial Statements of Enable Midstream Partners, LP as of December 31, 2016 and 2015 and for the years ended December 31, 2016, 2015 and 2014	Part II, Item 8 of Enable Midstream Partners, LP's Form 10-K for the year ended December 31, 2016	001-36413	Item 8
+101.INS	XBRL Instance Document			
+101.SCH	XBRL Taxonomy Extension Schema Document			
+101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document			
+101.DEF	XBRL Taxonomy Extension Definition Linkbase Document			
+101.LAB	XBRL Taxonomy Extension Labels Linkbase Document			
+101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document			

Exhibit 12

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(An Indirect Wholly Owned Subsidiary of CenterPoint Energy, Inc.)

COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2016	2015	2014	2013 (1)	2012 (1)
	(in millions)				
Net Income (loss)	$ 245	$ (912)	$ 323	$ 64	$ 137
Equity in (earnings) losses of unconsolidated affiliates, net of distributions	89	1,927	(2)	(58)	8
Income taxes expense (benefit)	162	(539)	188	371	246
Capitalized interest	(2)	(2)	(1)	(1)	(2)
	494	474	508	376	389
Fixed charges, as defined:					
Interest	122	137	141	154	179
Capitalized interest	2	2	1	1	2
Interest component of rentals charged to operating expense	3	3	3	6	9
Total fixed charges	127	142	145	161	190
Earnings, as defined	$ 621	$ 616	$ 653	$ 537	$ 579
Ratio of earnings to fixed charges	4.89	4.34	4.50	3.34	3.05

(1) Excluded from the computation of fixed charges for both the years ended December 31, 2013 and 2012 is interest income of $3 million, which is included in income tax expense.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-215833-02 on Form S-3 of our report dated February 28, 2017, relating to the consolidated financial statements of CenterPoint Energy Resources Corp. and subsidiaries, appearing in this Annual Report on Form 10-K of CenterPoint Energy Resources Corp. for the year ended December 31, 2016.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 28, 2017

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-215833-02 on Form S-3 of CenterPoint Energy Resources Corp. of our report dated February 21, 2017, relating to the consolidated financial statements of Enable Midstream Partners, LP and subsidiaries, appearing in this Annual Report on Form 10-K of CenterPoint Energy Resources Corp. for the year ended December 31, 2016.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 28, 2017

Exhibit 31.1

CERTIFICATIONS

I, Scott M. Prochazka, certify that:

1. I have reviewed this annual report on Form 10-K of CenterPoint Energy Resources Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2017

/s/ Scott M. Prochazka

Scott M. Prochazka

President and Chief Executive Officer

Exhibit 31.2

CERTIFICATIONS

I, William D. Rogers, certify that:

1. I have reviewed this annual report on Form 10-K of CenterPoint Energy Resources Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2017

/s/ William D. Rogers

William D. Rogers
Executive Vice President and Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of CenterPoint Energy Resources Corp. (the “Company”) on Form 10-K for the year ended December 31, 2016 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, I, Scott M. Prochazka, Chief Executive Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Scott M. Prochazka

Scott M. Prochazka
President and Chief Executive Officer
February 28, 2017

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of CenterPoint Energy Resources Corp. (the “Company”) on Form 10-K for the year ended December 31, 2016 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, I, William D. Rogers, Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ William D. Rogers

William D. Rogers
Executive Vice President and Chief Financial Officer
February 28, 2017