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, 2015

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, 2015: None

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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 2015, 2014 and 2013.

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," "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 own and operate natural gas distribution systems in six states. We also offer variable and fixed-price physical natural gas supplies primarily to commercial and industrial customers and gas utilities. As of December 31, 2015, we also owned approximately 55.4% of the limited partner interests in Enable Midstream Partners, LP (Enable), an unconsolidated partnership jointly controlled with OGE Energy Corp., which owns, operates and develops natural gas and crude oil infrastructure assets. References to “we,” “us,” and “our” mean CenterPoint Energy Resources Corp. (CERC Corp., together with our subsidiaries, CERC). We are an indirect, wholly-owned subsidiary of CenterPoint Energy, Inc. (CenterPoint Energy), a public utility holding company.

Our reportable business segments are Natural Gas Distribution, Energy Services, Midstream Investments and Other Operations. Substantially all of our former Interstate Pipelines business segment and Field Services business segment were contributed to Enable in May 2013. As a result, these business segments did not report operating results during 2014 or 2015. 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 Securities and Exchange Commission (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

Our natural gas distribution business (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 2015, approximately 39% of NGD’s total throughput was to residential customers and approximately 61% was to commercial and industrial and transportation customers.

The table below reflects the number of natural gas distribution customers by state as of December 31, 2015:

	Residential	Commercial/ Industrial	Total Customers
Arkansas	379,319	48,128	427,447
Louisiana	229,873	16,917	246,790
Minnesota	770,891	69,381	840,272
Mississippi	112,140	12,536	124,676
Oklahoma	89,756	10,789	100,545
Texas	1,567,866	96,170	1,664,036
Total NGD	3,149,845	253,921	3,403,766

NGD also provides unregulated services in Minnesota consisting of residential appliance repair and maintenance services along with heating, ventilating and air conditioning (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 2015, approximately 68% of the total throughput of NGD's business 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 2015, 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 2015 included BP Energy Company/BP Canada Energy Marketing (18.4% of supply volumes), Tenaska Marketing Ventures (14.5%), Sequent Energy Management (9.0%), ConocoPhillips Company (7.0%), Kinder Morgan Tejas Pipeline/Kinder Morgan Texas Pipeline (6.3%), Twin Eagle Resource Management (3.4%), CenterPoint Energy Services (3.2%), Mieco (3.1%), Oneok Energy Services (2.9%), and Trailstone NA Logistics (2.3%). Numerous other suppliers provided the remaining 30% 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 eight 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 and may also supplement contracted supplies and storage from time to time with stored liquefied natural gas and propane-air plant production.

NGD owns and operates an underground natural gas storage facility with a capacity of 7.0 billion cubic feet (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 million cubic feet (MMcf). It also owns eight propane-air plants with a total production rate of 180,000 Dekatherms (DTH) per day and on-site storage facilities for 12 million gallons of propane (1.0 Bcf natural gas equivalent). It owns a liquefied natural gas plant facility with a 12 million-gallon liquefied natural gas 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 entered into various asset management agreements (AMAs) associated with its utility distribution service in Arkansas, Louisiana, Mississippi, Oklahoma and Texas. Generally, these 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 agreed to release transportation and storage capacity to other parties to manage 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 received approval from the state regulatory commissions in Arkansas, Louisiana, Mississippi and Oklahoma to retain a share of the AMA proceeds. The agreements have varying terms, the longest of which expires in 2019.

Assets

As of December 31, 2015, 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 variable and fixed-priced physical natural gas supplies primarily to commercial and industrial customers and electric and gas utilities through CenterPoint Energy Services, Inc. (CES) and its subsidiary, CenterPoint Energy Intrastate Pipelines, LLC (CEIP).

In 2015, CES marketed approximately 618 Bcf of natural gas, related energy services and transportation to approximately 18,000 customers (including approximately 9 Bcf to affiliates) in 23 states. CES customers vary in size from small commercial customers to large utility companies.

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 Value at Risk (VaR).

Our risk control policy, which is overseen by CenterPoint Energy's Risk Oversight Committee (ROC), 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 proprietary or speculative commodity trading. The VaR limit within which CES currently operates, a $4 million maximum set by the 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 2015, 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

In May 2013, we, OGE Energy Corp. (OGE) and affiliates of ArcLight Capital Partners, LLC (ArcLight), formed Enable, initially a private limited partnership.

On April 16, 2014, Enable completed its initial public offering (IPO) of 28,750,000 common units at a price of $20.00 per unit, which included 3,750,000 common units sold by ArcLight pursuant to an over-allotment option that was fully exercised by the underwriters. Enable received $464 million in net proceeds from the sale of the units, after deducting underwriting fees, structuring fees and other offering costs. In connection with Enable's IPO, a portion of our common units were converted into subordinated units. As of December 31, 2015, CERC Corp. held an approximate 55.4% limited partner interest in Enable (consisting of 94,151,707 common units and 139,704,916 subordinated units) and OGE held an approximate 26.3% limited partner interest in Enable (consisting of 42,832,291 common units and 68,150,514 subordinated units). 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 as each own 50% of the management rights in the general partner of Enable. Sale of our ownership interests in Enable's general partner to anyone other than an affiliate prior to May 1, 2016 is prohibited by Enable's general partner's limited liability company agreement. 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.

As of December 31, 2015, CERC Corp. and OGE also own a 40% and 60% interest, respectively, in 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 45 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.

On January 28, 2016, CenterPoint Energy entered into a purchase agreement with Enable pursuant to which it agreed to purchase in a private placement (Private Placement) an aggregate of 14,520,000 10% Series A Fixed-to-Floating Non-Cumulative Redeemable Perpetual Preferred Units representing limited partner interests in Enable (Series A Preferred Units) for a cash purchase price of $25.00 per Series A Preferred Unit. The Private Placement closed on February 18, 2016. In connection with the Private Placement, Enable redeemed approximately $363 million of notes scheduled to mature in 2017 payable to our wholly-owned subsidiary. We made a dividend to CenterPoint Energy of $363 million and CenterPoint Energy used the dividend for its investment in the Series A Preferred Units.

Our investment in Enable is accounted for on an equity basis. Equity earnings associated with our interest in Enable are reported under the Midstream Investments segment.

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.

As of December 31, 2015, Enable's portfolio of energy infrastructure assets included approximately 12,400 miles of gathering pipelines, 13 major processing plants with approximately 2.3 Bcf per day of processing capacity and 2.3 Bcf per day of treating capacity, approximately 7,900 miles of interstate pipelines (including Southeast Supply Header, LLC (SESH)), approximately 2,200 miles of intrastate pipelines and eight storage facilities providing approximately 85.0 Bcf of storage capacity.

Enable's Gathering and Processing segment. Enable provides gathering, compression, treating, dehydration, processing and natural gas liquids (NGLs) fractionation for producers who are active in the areas in which Enable operates. Eight of Enable's processing plants in the Anadarko basin are interconnected through its super-header system. Enable has configured this system to facilitate the flow of natural gas from western Oklahoma and the Wheeler County area in the Texas Panhandle to the Bradley, Cox City, Thomas, McClure, Calumet, Clinton, South Canadian and Wheeler processing plants. Enable is constructing two cryogenic processing facilities to connect to its super-header system in Grady County, Oklahoma and Garvin County, Oklahoma, which are expected to add 400 MMcf per day of natural gas processing capacity. The first of the two new plants (the Bradley II Plant, formerly referred to as the Grady County Plant) is a 200 MMcf per day plant that is expected to be completed in the second quarter of 2016. The second plant (the Wildhorse Plant) is a 200 MMcf per day plant that is expected to be completed in late 2017. 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 owns and operates approximately 7,900 miles (including SESH) of interstate transportation pipelines with average firm contracted capacity of 7.19 Bcf per day (excluding SESH), for the year ended December 31, 2015. In addition, Enable owns and operates approximately 2,200 miles of intrastate transportation pipelines with average aggregate throughput of 1.84 trillion British thermal units per day for the year ended December 31, 2015. Enable also owns eight natural gas storage facilities with approximately 85.0 Bcf of aggregate capacity and approximately 1.9 Bcf per day of aggregate daily deliverability as of December 31, 2015. In addition, Enable owns an 8% contractual interest in Gulf South's Bistineau storage facility located in Bienville Parish, Louisiana, with 8.0 Bcf of capacity and 100 MMcf per day of deliverability as of December 31, 2015. Enable also contracts on a firm basis for 3.3 Bcf of high deliverability salt dome storage capacity from Cardinal in the Perryville and Arcadia natural gas storage fields. Enable's storage operations are located in Louisiana, Oklahoma and Illinois.

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.

SESH. SESH owns an approximately 290-mile interstate pipeline that runs from Perryville, Louisiana to southwestern Alabama near the Gulf Coast. The pipeline was placed into service in the third quarter of 2008. The rates charged by SESH for interstate transportation services are regulated by the FERC. During the year ended December 31, 2015, an average of approximately 1.5 Bcf per day was transported on this system.

On each of May 1, 2013 and May 30, 2014, we contributed a 24.95% interest in SESH to Enable. On June 30, 2015, we contributed our remaining 0.1% interest in SESH to Enable. The remaining 50% of SESH is owned by Spectra Energy Partners, LP.

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 15 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 Natural Gas Act and the Natural Gas Policy Act of 1978, 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 and its subsidiaries, including us, are subject to reporting and accounting requirements and are 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 of Texas (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 Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (2006 Act), which reauthorized the programs adopted under the Pipeline Safety Improvement Act of 2002 (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, the Pipeline and Hazardous Materials Safety Administration (PHMSA) at the Department of Transportation (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 Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (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.

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 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 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 Act 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 DOT's enforcement actions and penalties if we fail to comply with pipeline regulations. Please also see the discussion under "— Midstream Investments — Safety and Health Regulation" below.

Midstream Investments – Rate and Other Regulation

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

Interstate Natural Gas Pipeline Regulation

Enable's interstate pipeline systems — Enable Gas Transmission, LLC (EGT), Enable Mississippi River Transmission, LLC (MRT) and SESH — are subject to regulation by the FERC under the Natural Gas Act of 1938 (NGA) and are considered natural gas companies. Natural gas companies may not charge rates that have been determined to be unjust or unreasonable by the FERC. In addition, the FERC prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service. Under the NGA, the rates for service on Enable's interstate facilities must be just and reasonable and not unduly discriminatory. Generally, the maximum filed recourse rates for interstate pipelines are based on the pipeline's cost of service including recovery of and a return on the pipeline's actual prudent investment cost. Key determinants in the ratemaking process are costs of providing service, allowed rate of return, volume throughput and contractual capacity commitment assumptions. 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. Tariff changes can only be implemented upon approval by the FERC.

Market Behavior Rules; Posting and Reporting Requirements

On August 8, 2005, Congress enacted the Energy Policy Act of 2005 (EPAct of 2005). Among other matters, the EPAct of 2005 amended the NGA to add an anti-manipulation provision that makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulation to be prescribed by the FERC and, furthermore, provides the FERC with additional civil penalty authority. On January 19, 2006, the FERC issued Order No. 670, a rule implementing the anti-manipulation provisions of the EPAct of 2005. The rules make it unlawful for any entity, directly or indirectly in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC or the purchase or sale of transportation services subject to the jurisdiction of the FERC, to (1) use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The EPAct of 2005 also amends the NGA and the Natural Gas Policy Act of 1978 (NGPA) to give the FERC authority to impose civil penalties for violations of these statutes and FERC's regulations, rules, and orders, up to $1 million per day per violation for violations occurring after August 8, 2005. 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 Commodity Futures Trading Commission (CFTC) is directed under the Commodities Exchange Act (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.

Intrastate Natural Gas Pipeline and Storage Regulation

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

Intrastate natural gas transportation is largely regulated by the state in which the transportation takes place. An intrastate natural gas pipeline system may transport natural gas in interstate commerce provided that the rates, terms, and conditions of such transportation service comply with FERC regulation and Section 311 of the NGPA and Part 284 of the FERC's regulations. The NGPA regulates, among other things, the provision of transportation and storage services by an intrastate natural gas pipeline on behalf of an interstate natural gas pipeline or a local distribution company served by an interstate natural gas pipeline. Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. The rates under Section 311 are maximum rates and Enable may negotiate contractual rates at or below such maximum rates. Rates for service pursuant to Section 311 of the NGPA are generally subject to review and approval by the FERC at least once every five years. Should the FERC determine not to authorize rates equal to or greater than Enable's currently approved Section 311 rates, its business may be adversely affected.

Failure to observe the service limitations applicable to transportation services provided under Section 311, failure to comply with the rates approved by 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, it 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 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 results of operations and cash flows. 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 civil penalties as well as a requirement to disgorge charges collected for such service in excess of the rate established by the FERC.

States may regulate gathering pipelines. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, requirements prohibiting undue discrimination, and in some instances complaint-based rate regulation. Enable's gathering operations may be subject to ratable take and common purchaser statutes in the states in which they operate. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply and have the effect of restricting Enable's right as an owner of gathering facilities to decide with whom it contracts to purchase or transport natural gas.

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

For some time now, the FERC has been issuing regulatory assurances that necessarily balance the anti-discrimination and undue preference requirements of common carriage with the expectations of investors in new and expanding petroleum pipelines. There is an inherent tension between the requirements imposed upon a common carrier and the need for owners of petroleum pipelines to be able to enter into long-term, firm contracts with shippers willing to make the commitments which underpin such large capital investments. The FERC's solution has been to allow carriers to hold an "open season" prior to the in-service date of pipeline, during which time interested shippers can make commitments to the proposed pipeline project. Throughput commitments from interested shippers during an open season can be for firm service or for non-firm service. Typically, such an open season is for a 30-day period, must be publicly announced, and culminates in interested parties entering into transportation agreements with the carrier. Under FERC precedent, a carrier typically may reserve up to 90% of available capacity for the provision of firm service to shippers making a commitment. At least 10% of capacity ordinarily is reserved for "walk-up" shippers.

Midstream Investments – 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 pipeline safety regulations, but natural gas gathering pipelines are subject to the pipeline safety regulations only to the extent they are classified as regulated gathering pipelines. In addition, several NGL pipeline facilities and crude oil pipeline facilities are regulated as hazardous liquids pipelines. Pursuant to various federal statutes, including the Natural Gas Pipeline Safety Act of 1968 (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. PHMSA has developed regulations that require natural gas pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in high consequence areas. Although many of Enable's pipeline facilities fall within a class that is currently not subject to these integrity management requirements, Enable may incur significant costs and liabilities associated with repair, remediation, preventive or mitigating measures associated with its non-exempt pipelines. Additionally, should Enable fail to comply with DOT or comparable state regulations, it could be subject to penalties and fines. If future DOT pipeline integrity management regulations were to require that Enable expand its integrity managements program to currently unregulated pipelines, including gathering lines, its 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.

In order 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 disposal areas, fuel storage and management facilities and other locations and facilities.

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 affect the environment. For example, the Environmental Protection Agency (EPA) has also 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 National Emission Standards for Hazardous Air Pollutants (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 greenhouse gases (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 effect 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 natural gas liquids 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 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 Resource Conservation and Recovery Act (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

The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (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

Manufactured Gas Plant Sites. We and our predecessors operated manufactured gas plants (MGPs) in the past. With respect to certain Minnesota MGP sites, we have completed state-ordered remediation and continue state-ordered monitoring and water treatment. As of December 31, 2015, we 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 we believe we may have responsibility was $5 million to $29 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 potentially responsible parties (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 us or may have been owned by one of our former affiliates. We do not expect the ultimate outcome of these matters to have a material adverse effect on our financial condition, results of operations or cash flows.

Asbestos. Some facilities owned by our predecessors contain or have contained asbestos insulation and other asbestos-containing materials. We or our predecessor companies have been named, along with numerous others, as defendants in lawsuits filed by a number of individuals who claim injury due to exposure to asbestos. Some of the claimants have worked at locations owned by us, but most existing claims relate to facilities previously owned by our subsidiaries. We anticipate that additional claims like those received may be asserted in the future. Although their ultimate outcome cannot be predicted at this time, we intend to continue vigorously contesting claims that we do not consider to have merit and do not expect, based on our experience to date, these matters, either individually or in the aggregate, to have a material adverse effect on our financial condition, results of operations or cash flows.

Other Environmental. From time to time we identify the presence of environmental contaminants on property where we conduct or have conducted operations. Other such sites involving contaminants may be identified in the future. We have remediated and expect to continue to remediate identified sites consistent with our legal obligations. From time to time we have received notices from regulatory authorities or others regarding our status as a PRP in connection with sites found to require remediation due to the presence of environmental contaminants. In addition, we have 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, we do not expect, based on our experience to date, these matters, either individually or in the aggregate, to have a material adverse effect on our financial condition, results of operations or cash flows.

EMPLOYEES

As of December 31, 2015, we had 3,421 full-time employees. The following table sets forth the number of our employees by business segment as of December 31, 2015:

Business Segment	Number	Number Represented by Unions or Other Collective Bargaining Groups
Natural Gas Distribution	3,286	1,173
Energy Services	135	—
Total	3,421	1,173

As of December 31, 2015, approximately 34% of our employees were covered by collective bargaining agreements. Two collective bargaining agreements with Professional Employees International Union Local 12, which collectively cover approximately 4% of our employees, are scheduled to expire in March and May of 2016. We believe we have good relationships with these bargaining units and expect to negotiate new agreements in 2016.

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 business.

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, 2015, we had $2.4 billion of outstanding indebtedness on a consolidated basis. As of December 31, 2015, approximately $875 million of this debt is required to be paid through 2018. 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;

- 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;

- market perceptions of our and CenterPoint Energy's ability to access capital markets on reasonable terms;

- our exposure to GenOn Energy, Inc. (GenOn) (formerly known as RRI Energy, Inc., Reliant Energy, Inc. and Reliant Resources, Inc.(RRI)), a wholly-owned subsidiary of NRG Energy, Inc. (NRG) in connection with its indemnification obligations arising in connection with its separation from CenterPoint Energy;

- 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 the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. For example, based on the sustained low Enable common unit price and further declines in such price during the three months ended September 30, 2015 and December 31, 2015, respectively, as well as the market outlook for continued depressed crude oil and natural gas prices impacting the midstream oil and gas industry, we determined in connection with our preparation of financial statements for the three months ended September 30, 2015 and December 31, 2015, that an other than temporary decrease in the value of our investment in

Enable had occurred. We wrote down the value of our investment in Enable to its estimated fair value which resulted in impairment charges of $250 million as of September 30, 2015 and $975 million as of December 31, 2015. Our total impairment loss included impairment charges totaling $1,846 million composed of the impairments 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.

If Enable's unit price, distributions or earnings further decline for reasons including, but not limited to, continued declines in commodity prices and producer activity, 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. As of December 31, 2015, the carrying value of our investment in Enable is $11.09 per unit, which includes the common and subordinated units representing limited partner interests, general partner interest and incentive distribution rights we hold. As of December 31, 2015, Enable's common unit price closed at $9.20. The lowest close price for Enable's common units through February 12, 2016 was $5.80. 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 or further declines in such 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, 2015, CenterPoint Energy and its subsidiaries other than us had approximately $600 million principal amount of debt required to be paid through 2018. This amount excludes principal repayments of approximately $1.2 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 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 and state commissions based on an analysis of our invested capital and our expenses in a test year. Thus, the rates that we are allowed to charge may not match our costs at any given time, which is referred to as "regulatory lag." The regulatory process in which rates are determined may not always result in rates that will produce full recovery of our costs and enable us to earn a reasonable return on our invested capital.

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 in order 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 in order 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 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.

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 (55.4% of Enable's outstanding limited partnership interests as of December 31, 2015), 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. CenterPoint Energy also holds $363 million of Enable's Series A Preferred Units. 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 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 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; and
- other business risks affecting its cash levels.

The amount of cash Enable has available for distribution on its units, including the Series A Preferred Units, to us 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 units, including the Series A Preferred 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 New York Stock Exchange. 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.

Enable generates a substantial portion of its gross margins under long-term, fee-based agreements. For the year ended December 31, 2015, approximately 81% of Enable's gross margin was generated from contracts that are fee-based and approximately 56% of its gross margin was attributable to fees associated with firm contracts or contracts with minimum volume commitment features. As these and other contracts expire, Enable may have to negotiate extensions or renewals with existing suppliers and customers or enter into new contracts with other suppliers and customers. Enable may be unable to obtain new contracts on favorable commercial terms, if at all. It also may be unable to maintain the economic structure of a particular contract with an existing customer or the overall mix of its contract portfolio. For example, depending on prevailing market conditions at the time of a contract renewal, gathering and processing customers with fixed-fee or fixed-margin contracts may desire to enter into contracts under different fee arrangements. To the extent Enable is unable to renew its existing contracts on terms that are favorable to it, if at all, or successfully manage its overall contract mix over time, its revenue, results of operations and distributable cash flow could be adversely affected.

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

Enable provides firm transportation and storage services to certain key customers on its system. Its major transportation customers are affiliates of CenterPoint Energy, Laclede, OGE, American Electric Power Company, Inc. and XTO Energy Inc., an affiliate of Exxon Mobil Corporation.

The loss of all or even a portion of the interstate or intrastate transportation and storage services for any of these customers, the failure to extend or replace these contracts or the extension or replacement of these contracts on less favorable terms, as a result of competition or otherwise, could adversely affect Enable's financial position, results of operations and its 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 continued availability of natural gas, NGLs and crude oil production. Enable has no control over the level of drilling activity in its areas of operation, the amount of reserves associated with wells connected to its systems or the rate at which production from a well declines. In addition, Enable's cash flows associated with wells currently connected to its systems will decline over time. 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 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 these systems, its ability to compete for volumes from successful new wells and its ability to expand 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 have a material adverse effect on its results of operations and distributable cash flow. 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, NGLs and crude oil reserves. Drilling and production activity generally decreases as commodity prices decrease. In general terms, the prices of natural gas, crude oil and other hydrocarbon products fluctuate in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond Enable's control. Because of these factors, even if new natural gas 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. Over the course of 2015 and continuing into 2016, natural gas and crude oil prices have dropped to their lowest levels in over 10 years from a high of $13.31 per MMBtu in July 2008 to $1.63 per MMBtu at December 23, 2015 and $145.31 per barrel in July 2008 to $26.19 per barrel at February 11, 2016, respectively. A sustained decline 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 have a material adverse effect on its business, 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 have a material adverse effect on its financial position, results of operations and distributable cash flow.

Enable’s industry is highly competitive, and increased competitive pressure could adversely affect its financial position, results of operations and distributable cash flow.

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 crude oil, natural gas and petrochemical 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 transportation services. All of these competitive pressures could adversely affect Enable’s results of operations and distributable cash flow.

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, 2015, Enable stated that it expects that its expansion capital will be approximately $375 million and its maintenance capital could range from approximately $105 million to $125 million for the year ending December 31, 2016. For example, Enable is currently constructing two cryogenic processing facilities that it plans to connect to its super-header system in Grady and Garvin County, Oklahoma, which Enable expects will add 400 MMcf per day of combined natural gas processing capacity. Enable expects that the first of the two new plants (the Bradley II Plant) will be completed in the second quarter of 2016. Enable expects that the second plant (the Wildhorse Plant), a 200 MMcf per day plant, will be completed in late 2017. 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 results of operations and its 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 results of operations and its 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 results of operations and its 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 its ability to make cash distributions.

Enable's results of operations and its 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 its 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, liquefied natural gas, 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. Over the course of 2015 and continuing into 2016, natural gas and crude oil prices have dropped to their lowest levels in over 10 years from a high of $13.31 per MMBtu in July 2008 to $1.63 per MMBtu at December 23, 2015 and $145.31 per barrel in July 2008 to $26.19 per barrel at February 11, 2016, respectively.

Enable's keep-whole natural gas processing arrangements, which accounted for 5% of its natural gas processed volumes in 2015, expose it to fluctuations in the pricing spreads between NGL prices and natural gas prices. Under these arrangements, the processor processes raw natural gas to extract NGLs and delivers to the producer the natural gas equivalent Btu value of raw natural gas received from the producer in the form of processed natural gas. The processor retains the processed NGLs and to sell them for its own account. Accordingly, the processor's cost of natural gas and NGLs is a function of the difference between the value of the NGLs produced and the cost of the processed natural gas used to replace the natural gas equivalent Btu value of those NGLs. Therefore, if natural gas prices increase and NGL prices do not increase by a corresponding amount, the processor has to replace the Btu of natural gas at higher prices and cost of natural gas and NGLs sold are negatively affected.

Enable's percent-of-proceeds and percent-of-liquids natural gas processing agreements accounted for 47% of its natural gas processed volumes in 2015. Under percent-of-proceeds processing arrangements, the processor generally purchases unprocessed natural gas from the producer for a purchase price that is based on published natural gas and NGL index prices. The purchase price for unprocessed natural gas is calculated based on a percentage of the quantity of natural gas and NGLs that would result from processing the gas purchased. Accordingly, the processor's cost of goods sold is a percentage of the index price value of the natural gas and NGLs contained in the unprocessed natural gas. If Enable is unable to sell the processed natural gas and NGLs at a higher price than it pays, Enable's margins from sale of goods are negatively affected. Additionally, if the amount of processed natural gas or NGLs recovered during processing is less than the amount upon which the purchase price was based, Enable's margins from sale of goods may be negatively affected.

Under percent-of-liquids processing arrangement, the processor generally purchases the NGLs in unprocessed natural gas received from the producer, processes the natural gas, and returns the processed natural gas to the producer. The purchase price for NGLs is based on published NGL index prices and is calculated based on a percentage of the quantity of NGLs that would result from processing the gas. Accordingly, the processor's cost of goods sold is a percentage of the index price value of NGLs contained in the unprocessed natural gas. If Enable is unable to sell the NGLs recovered during processing at a higher price than it pays, Enable's margins from sale of goods are negatively affected. Additionally, if the amount of NGLs recovered during processing is less than the amount upon which the purchase price was based, Enable's margins from sale of goods may 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 it is a net buyer of natural gas) and a net long position in NGLs (meaning that it 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 has limited experience in the crude oil gathering business.

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

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

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 long-term, 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, 2015, approximately 60% of Enable's contracted transportation firm capacity and 44% of its contracted storage firm capacity was subscribed under such "negotiated rate" contracts. These contracts generally do not include provisions allowing for adjustment for increased costs due to inflation, pipeline safety activities or other factors that are not tied to an applicable tracking mechanism authorized by 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 results of operations and its ability to make cash distributions could be adversely affected.

Enable depends upon third-party natural gas pipelines to deliver natural gas to, and take natural gas from, its transportation systems. Enable also depends on third-party facilities to transport and fractionate NGLs that are delivered to the third party at the tailgates of the processing plants. Fractionation is the separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale. For example, an outage or disruption on certain pipelines or fractionators operated by a third party could result in the shutdown of certain of 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 results of operations and its ability to make cash distributions to unitholders 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 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 have a material adverse effect on the success of these operations and Enable's financial position and results of operations.

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 negatively affect Enable's financial condition, results of operations and distributable cash flows. 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.

If Enable does not make acquisitions or is unable to make acquisitions on economically acceptable terms, its future growth will be adversely affected.

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

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

As of December 31, 2015, Enable had approximately $2.7 billion of long-term debt outstanding, excluding the premiums on their senior notes and $363 million of long-term notes payable—affiliated companies due to CERC Corp. In addition, Enable had $236 million outstanding under its commercial paper program as of December 31, 2015. Enable has a $1.75 billion revolving credit facility for working capital, capital expenditures and other partnership purposes, including acquisitions, of which $1.2 billion was available as of December 31, 2015. 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 business, financial condition, results of operations and ability to make quarterly 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 cash flows.

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 results of operations and its 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. There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations and those costs may be even more significant in the future.

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, produced water and air emissions related to its operations and historical industry operations and waste disposal practices. These activities are subject to stringent and complex federal, state and local laws and regulations governing environmental protection, including the discharge of materials into the environment and the protection of plants, wildlife, and natural and cultural resources. These laws and regulations can restrict or impact 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 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/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. Many of Enable’s customers commonly use hydraulic fracturing techniques in their drilling and completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas commissions. In addition, certain federal agencies have proposed additional laws and regulations to more closely regulate the hydraulic fracturing process. For example, in September 2015, the EPA published updates to new source performance standard requirements that would 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. Congress from time to time has considered the adoption of legislation to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and to require disclosure of the chemicals used in the hydraulic fracturing process. Some states have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular, in some cases banning hydraulic fracturing entirely. Other governmental agencies, including the DOE and the EPA, have evaluated or are evaluating various other aspects of hydraulic fracturing such as the potential environmental effects of hydraulic fracturing on drinking water and groundwater.

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.

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 have a material adverse effect on Enable’s 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 condition, results of operations and cash flows and its 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 cash flows and its 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.

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 operators, including Enable, to, among other things:

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

Although many of Enable’s pipelines fall within a class that is currently not subject to these requirements, it may incur significant cost and liabilities associated with repair, remediation, preventive or mitigation measures associated with its non-exempt pipelines. Should Enable fail to comply with DOT or comparable state regulations, it could be subject to penalties and fines. Also, the scope of the integrity management program and other related pipeline safety programs could be expanded in the future. Such future requirements could adversely affect Enable’s financial position, results of operations and its ability to make cash distributions.

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.

In order 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 disposal areas, fuel storage and management facilities and other locations and facilities.

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 affect 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.

We and OGE currently have general liability and property insurance in place to cover certain of Enable's facilities in amounts that we consider appropriate. Such policies are subject to certain limits and deductibles. 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 is not fully insured against all risks inherent in its business. 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 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, Incorporated (Reliant Energy), a predecessor of CenterPoint Energy, directly or through subsidiaries, including us in some cases. Through a series of transactions, the assets and businesses were transferred to a predecessor of RRI.

In connection with the organization and capitalization of RRI (now GenOn), that company and its subsidiaries assumed liabilities associated with various assets and businesses Reliant Energy transferred to them. RRI also agreed to indemnify, and cause the applicable transferee subsidiaries to indemnify, CenterPoint Energy and its subsidiaries, including us, with respect to liabilities associated with the transferred assets and businesses. These indemnity provisions were intended to place sole financial responsibility on RRI and its subsidiaries for all liabilities associated with the current and historical businesses and operations of RRI, regardless of the time those liabilities arose. If RRI (now GenOn) were unable to satisfy a liability that has been so assumed in circumstances in which Reliant Energy and its subsidiaries were not released from the liability in connection with the transfer, we and CenterPoint Energy could be responsible for satisfying the liability.

Prior to the distribution of CenterPoint Energy's ownership in RRI to its shareholders, we had guaranteed certain contractual obligations of what became RRI's trading subsidiary. When the companies separated, RRI agreed to secure us against obligations under the guarantees RRI had been unable to extinguish by the time of separation. Pursuant to such agreement, as amended in December 2007, RRI (now GenOn) agreed to provide to us cash or letters of credit as security against our obligations under our remaining guarantees for demand charges under certain gas transportation agreements if and to the extent changes in market conditions expose us to a risk of loss on those guarantees based on an annual calculation, with any required collateral to be posted each December. The undiscounted maximum potential payout of the demand charges under these transportation contracts, which will be in effect until 2018, was approximately $27 million as of December 31, 2015. Based on market conditions in the fourth quarter of 2015 at the time the most recent annual calculation was made under the agreement, GenOn was not obligated to post any security. If GenOn should fail to perform the contractual obligations, we could have to honor our guarantee and, in such event, any collateral then provided as security may be insufficient to satisfy our obligations.

If GenOn were unable to meet its obligations, it could consider, among various options, restructuring under the bankruptcy laws, in which event GenOn might not honor its indemnification obligations and claims by GenOn's creditors might be made against CenterPoint Energy as its former owner.

Reliant Energy and RRI (GenOn's predecessor) are named as defendants in a number of lawsuits arising out of sales of natural gas in California and other markets. Although these matters relate to the business and operations of GenOn, claims against Reliant Energy have been made on grounds that include liability of Reliant Energy as a controlling shareholder of GenOn's predecessor, and CES, a subsidiary of CERC Corp., is a defendant in a case now pending in federal court in Nevada. We and CenterPoint Energy could incur liability if claims in one or more of these lawsuits were successfully asserted against us or CenterPoint Energy and indemnification from GenOn were determined to be unavailable or if GenOn were unable to satisfy indemnification obligations owed with respect to those claims.

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

We and Enable are subject to cyber and physical security risks related to breaches in the systems and technology used (i) to manage operations and other business processes and (ii) to protect sensitive information maintained in the normal course of business. The distribution of natural gas to our customers and the gathering, processing and transportation of natural gas or other commodities from Enable's gathering, processing and pipeline facilities, are dependent on communications among Enable's facilities and with third-party systems that may be delivering natural gas or other commodities into or receiving natural gas 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 ability or Enable's ability to conduct operations and control assets. Cyber-attacks could also result in the loss of confidential or proprietary data or security breaches of other information technology systems that could disrupt operations and critical business functions, adversely affect reputation, 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, gas distribution and pipeline systems may be targets of terrorist activities that could disrupt either our or Enable's ability to conduct our respective businesses and 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 system failures that impair our information technology infrastructure 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 the modification of existing laws and regulations, to reduce emissions of GHGs, and there has been a wide-ranging policy debate, both nationally and internationally, regarding the impact of these gases and possible means for their regulation. 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 gas transmission and field services businesses could experience lower revenues. Another possible 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.

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. There are six separate bargaining units in CERC, each with a unique collective bargaining agreement. Two collective bargaining agreements with Professional Employees International Union Local 12 are scheduled to expire in March and May of 2016. Two additional collective bargaining agreements will be renegotiated in 2017. 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 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 and financial condition could be materially and adversely affected.

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

From time to time, we and Enable have made and may continue to make acquisitions of businesses and assets. However, suitable acquisition candidates may not continue to be available on terms and conditions we or Enable, as the case may be, find acceptable. In addition, 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.

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 13 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 unfavorable economic conditions in our service territories.

Our businesses are affected by the economic climate in our service territories, which could impact our ability to grow our customer base and our rate of growth or result in reduced energy consumption by our customers. Some economic sectors important to our customer base may be affected. For example, our business is largely concentrated 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, 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.

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 Enegy'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 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 13(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 $43 million and $405 million to our parent in 2015 and 2014, respectively. No dividends were paid to our parent in 2013.

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 own and operate natural gas distribution systems. A wholly-owned subsidiary of CERC Corp. offers variable and fixed-price physical natural gas supplies primarily to commercial and industrial customers and electric and gas utilities. As of December 31, 2015, CERC Corp. also owned approximately 55.4% of the limited partner interests in Enable Midstream Partners, LLC (Enable), which owns, operates and develops natural gas and crude oil infrastructure assets. We are an indirect, wholly-owned subsidiary of CenterPoint Energy, Inc. (CenterPoint Energy).

Business Segments

Because we are an indirect, wholly-owned subsidiary of CenterPoint Energy, our determination of reportable segments considers the strategic operating units under which CenterPoint Energy manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments. 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. 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 which we are subject. Our natural gas distribution services are subject to rate regulation and are reported in the Natural Gas Distribution business 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, natural gas liquids (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." A summary of our reportable business segments as of December 31, 2015 is set forth below:

Natural Gas Distribution

We own and operate our regulated natural gas distribution business (NGD), which engages in intrastate natural gas sales to, and natural gas transportation and storage for, approximately 3.4 million residential, commercial and industrial customers in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas.

Energy Services

Our operations also include non-rate regulated natural gas sales to, and transportation and storage services for, commercial and industrial customers in 23 states in the central United States.

Midstream Investments

We have a significant equity investment in Enable, an unconsolidated subsidiary that owns, operates and develops natural gas and crude oil assets. Our Midstream Investments segment includes equity earnings associated with the operations of Enable.

Other Operations

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, our business is largely concentrated 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. Reduced demand and lower energy prices could lead to financial pressure on some of our customers who operate within the energy industry and impact the growth rate of our customer base. 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 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 2015. Historically, NGD has utilized weather hedges to help reduce the impact of mild weather on its financial results. However, NGD did not enter a weather hedge for the 2015–2016 winter season 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. In 2014, we experienced a colder than normal January and February and milder temperatures for the rest of the year, including the summer months, in the Houston area. In 2013, we experienced a colder than normal spring and very cold weather in November and December in Houston and all of the states in which we have gas customers. 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 addition, in many of our service areas, particularly in the Houston area and in Minnesota, we have benefited from a growth in the number of customers that 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 our gas distribution 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 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 hedge its exposure to price movements, it does not engage in speculative or proprietary trading and maintains a low value at risk level, or VaR, to avoid significant financial exposures. 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.

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 in order 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 regulatory treatment, 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 primarily 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, which depends significantly on the level of production from natural gas wells connected to its 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, as production must be maintained or increased by new drilling or other activity, because the production rate of oil and gas wells declines over time.

Oil and gas producers’ willingness to engage in new drilling is determined by a number of factors, the most important of which are the prevailing and projected prices of natural gas, NGLs and crude oil, the cost to drill and operate a well, the availability and cost of capital and environmental and government regulations. Commodity price changes impact the commodity-based portion of Enable’s gross margin, its producer customers’ decisions to drill and complete wells and its transportation and storage customers decisions to contract capacity on Enable’s system. Prices of natural gas, crude oil, and NGLs have historically experienced periods of significant volatility. Enable’s results are also impacted by the price differentials between receipt and delivery points on its systems. 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. The prices of crude oil, NGLs and natural gas have continued to decline significantly. Over the course of 2015 and continuing into 2016, natural gas and crude oil prices have dropped to their lowest levels in over 10 years from a high of $13.31 per MMBtu in July 2008 to $1.63 per MMBtu at December 23, 2015 and $145.31 per barrel in July 2008 to $26.19 per barrel at February 11, 2016, respectively. Should lower commodity prices persist, or should commodity prices decline further, Enable’s future volumes and cash flows may be negatively impacted. The level of drilling is expected to positively correlate with long-term trends in commodity prices. Similarly, production levels nationally and regionally generally tend to positively correlate with drilling activity.

Over the past several years, there has been a fundamental shift in U.S. natural gas and crude oil production towards tight gas formations and shale plays. The emergence of these plays and advancements in technology have been crucial factors that have allowed producers to efficiently extract significant volumes of natural gas and crude oil. Recently, declining crude oil, natural gas and NGL prices have resulted in decreases in current and anticipated crude oil and natural gas drilling activity. Should lower prices and producer activity persist for a sustained period or should prices and producer activity decline further, Enable’s future volumes and cash flows may be negatively impacted. To maintain and increase throughput volumes on its systems, Enable must continue to contract its capacity to shippers, including producers and marketers. Enable’s transportation and storage systems compete for customers based on the type of service a customer needs, operating flexibility, receipt and delivery points and geographic flexibility and available capacity and price. To maintain and increase Enable’s transportation and storage volumes, it must continue to contract its capacity to shippers, including producers, marketers, local distribution companies, power generators and industrial end users.

Natural gas continues to be a critical component of energy supply and demand in the United States. 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 electricity generation by natural gas-fired electricity generation due to the low prices of natural gas and stricter government environmental regulations on the mining and burning of coal. According to the U.S. Energy Information Administration (EIA), demand for natural gas in the electric power sector is projected to increase from approximately 8.2 Tcf in 2013 to approximately 9.4 Tcf in 2040, with a portion of the growth attributable to the retirement of 37 gigawatts of coal-fired capacity by 2020. The EIA also predicts that low natural gas prices will lead to the increase of natural gas consumption in the industrial sector and to the United States becoming a new exporter of natural gas by mid-2017. However, the EIA expects growth in natural gas consumption for power generation, exploration and in the industrial sector to be partially offset by decreased usage in the residential sector. Enable's management believes that increasing consumption of natural gas over the long term will continue to drive demand for Enable's natural gas gathering, processing, transportation and storage services.

Enable may access the capital markets to fund 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 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 the FERC and other federal and state regulatory agencies, including the DOT, has a significant impact on Enable's business. For example, PHMSA has established pipeline integrity management programs that require more frequent inspections of pipeline facilities and other preventative measures, which may increase 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.

Significant Events

Impairment of Equity Investment. We recognized a loss of $1,633 million from our investment in Enable for the year ended December 31, 2015. This loss included 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 further discussion of the impairment, see Note 10 to our consolidated financial statements.

Texas Coast Rate Case. On March 27, 2015, NGD filed a Statement of Intent with each of the 49 cities and unincorporated areas within its Texas Coast service territory for a $6.8 million annual revenue increase. This increase was based on a rate base of $132.3 million and a return on equity (ROE) of 10.25%. On July 6, 2015, the parties agreed to a settlement providing for a $4.9 million annual increase to rates, an ROE of 10.0%, 54.5% equity and authorized overall rate of return of 8.23%. This settlement resolved six outstanding cases on appeal: one on remand at the Railroad Commission of Texas (Railroad Commission) and five cost of service adjustment (COSA) appeals at the district court. The Railroad Commission unanimously approved the settlement on August 25, 2015. Rates were implemented in September 2015.

Arkansas Formula Rate Review Plan (FRP) Legislation. On March 30, 2015, HB 1655 was signed by Governor Hutchinson and became Act 725 (the Act). This legislation introduces a FRP mechanism for utilities and requires that the Arkansas Public Service Commission (APSC) approve a FRP if requested by a utility and allows a utility to use a projected test year. The Act establishes certain parameters, including the use of an earnings band 50 basis points above and below the allowed return on equity and annual rate changes not to exceed 4% of prior year revenues per rate class. The details of a FRP that were not established by the Act are being defined during the rate proceeding currently in process.

Arkansas Rate Case. On August 17, 2015, NGD filed a Notice of Intent to File a general rate case with the APSC. The rate case was filed on November 10, 2015 seeking a $35.6 million increase in revenue requirement and a 10.3% ROE. A procedural schedule has been established with a hearing scheduled for July 12, 2016. A final determination by the APSC is expected in the third quarter of 2016.

Minnesota Rate Case. In August 2015, NGD filed a general rate case with the Minnesota Public Utilities Commission (MPUC) requesting an annual increase of $54.1 million. On September 10, 2015, the MPUC approved an interim increase of $47.8 million in revenues effective October 2, 2015, subject to a refund. The MPUC is expected to issue a final decision in mid-2016 with final rates effective by the end of 2016.

Exercise of Put Right. On June 30, 2015, we closed our put right with respect to our remaining interest in Southeast Supply Header, LLC (SESH) and contributed to Enable our remaining 0.1% interest in SESH in exchange for 25,341 limited partner units of Enable. No cash payment was required to be made pursuant to the Enable formation agreements in connection with our exercise.

Private Placement. On January 28, 2016, CenterPoint Energy entered into a purchase agreement with Enable pursuant to which it agreed to purchase in a private placement (Private Placement) an aggregate of 14,520,000 10% Series A Fixed-to-Floating Non-Cumulative Redeemable Perpetual Preferred Units representing limited partner interests in Enable (Series A Preferred Units) for a cash purchase price of $25.00 per Series A Preferred Unit. The Private Placement closed on February 18, 2016. In connection with the Private Placement, Enable redeemed approximately $363 million of notes scheduled to mature in 2017 payable to our wholly-owned subsidiary. We made a dividend to CenterPoint Energy of $363 million and CenterPoint Energy used the dividend for its investment in the Series A Preferred Units.

Continuum Acquisition. On January 29, 2016, CenterPoint Energy Services (CES), our wholly-owned subsidiary, announced an agreement to acquire the retail commercial and industrial businesses of Continuum Energy Services (Continuum), a Tulsa and Houston-based company, for $77.5 million plus working capital. The transaction is conditioned upon the receipt of certain third party consents and approvals. We expect the transaction to close by the end of the first quarter of 2016.

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 growth capital; and
  - the availability and prices of raw materials and services for current and future construction projects;
- 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, health care reform, financial reform, tax legislation and actions regarding the rates charged by our regulated businesses;
- timely and appropriate rate actions that allow recovery of costs and a reasonable return on investment;
- industrial, commercial and residential growth in our service territories and changes in market demand, including the effects of energy efficiency measures and demographic patterns;
- 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;

- 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, 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 Energy, Inc. (formerly known as RRI Energy, Inc., Reliant Energy, Inc. and Reliant Resources, Inc.), a wholly-owned subsidiary of NRG Energy, Inc., and its subsidiaries to satisfy their obligations to us, including indemnity obligations, or obligations in connection with the contractual arrangements pursuant to which we are their guarantor;
- 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 Securities and Exchange Commission.

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, 2015, 2014 and 2013, 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,		
	2015	2014	2013
	(in millions)		
Revenues	$ 4,527	$ 6,367	$ 5,522
Expenses:			
Natural gas	3,102	4,921	3,908
Operation and maintenance	741	751	828
Depreciation and amortization	227	206	230
Taxes other than income taxes	144	154	155
Total	4,214	6,032	5,121
Operating Income	313	335	401
Interest and other finance charges	(137)	(141)	(154)
Equity in Earnings (Losses) of unconsolidated affiliates	(1,633)	308	188
Other income, net	6	9	—
Income (Loss) Before Income Taxes	(1,451)	511	435
Income Tax Expense (Benefit)	(539)	188	371
Net Income (Loss)	$ (912)	$ 323	$ 64

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 10 to our consolidated financial statements;
- a $22 million decrease in operating income (discussed by segment below); and
- a $3 million decrease in other income, net.

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 37.1% and 36.8% for the years ended December 31, 2015 and 2014, respectively.

2014 Compared to 2013

Net Income. We reported net income of $323 million for 2014 compared to $64 million for 2013.

The increase in net income of $259 million was due to the following key factors:

- a $183 million decrease in income tax expense discussed below;
- a $120 million increase in equity earnings of unconsolidated affiliates; and
- a $13 million decrease in interest expense.

These increases were partially offset by a $66 million decrease in operating income (discussed below by segment).

Income Tax Expense. We reported an effective tax rate of 36.8% and 85.3% for the years ended December 31, 2014 and 2013, respectively. The effective tax rate of 85.3% for 2013 is primarily attributable to a net $198 million charge to deferred tax expense due to the formation of Enable. For more information, see Note 12 to our consolidated financial statements.

RESULTS OF OPERATIONS BY BUSINESS SEGMENT

The following table presents operating income (loss) for each of our business segments for 2015, 2014 and 2013. 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,		
	2015	**2014**	**2013**
		(in millions)	
Natural Gas Distribution	$ 273	$ 287	$ 263
Energy Services	42	52	13
Interstate Pipelines	—	—	72
Field Services	—	—	73
Other Operations	(2)	(4)	(20)
Total Consolidated Operating Income	$ 313	$ 335	$ 401

Natural Gas Distribution

The following table provides summary data of our Natural Gas Distribution business segment for 2015, 2014 and 2013:

	Year Ended December 31,		
	2015	2014	2013
	(in millions, except throughput and customer data)		
Revenues	$ 2,632	$ 3,301	$ 2,863
Expenses:			
Natural gas	1,297	1,961	1,607
Operation and maintenance	697	700	667
Depreciation and amortization	222	201	185
Taxes other than income taxes	143	152	141
Total expenses	2,359	3,014	2,600
Operating Income	$ 273	$ 287	$ 263
Throughput (in Bcf):			
Residential	171	197	182
Commercial and industrial	262	270	265
Total Throughput	433	467	447
Number of customers at end of period:			
Residential	3,149,845	3,124,542	3,090,966
Commercial and industrial	253,921	249,272	247,100
Total	3,403,766	3,373,814	3,338,066

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 higher gross receipt taxes of $10 million were offset by a corresponding decrease in the related revenues.

2014 Compared to 2013. Our Natural Gas Distribution business segment reported operating income of $287 million for 2014 compared to $263 million for 2013.

Operating income increased $24 million as a result of the following key factors:

- increased usage of $16 million as a result of colder weather compared to the prior year, partially mitigated by weather hedges and weather normalization adjustments;

- rate increases of $37 million; and

- increased economic activity across our footprint of $10 million, including the addition of approximately 36,000 customers.

These increases were partially offset by:

- increased contractor expense of $10 million, including pipeline integrity work;

- higher depreciation and amortization of $16 million;

- increase in taxes of $7 million; and

- increased other operating expenses of $6 million.

Increased expense related to energy efficiency programs of $8 million and increased expense related to higher gross receipt taxes of $4 million were offset by a corresponding increase in the related revenues.

Energy Services

The following table provides summary data of our Energy Services business segment for 2015, 2014 and 2013:

	Year Ended December 31,		
	2015	**2014**	**2013**
	(in millions, except throughput and customer data)		
Revenues	$ 1,957	$ 3,179	$ 2,401
Expenses:			
Natural gas	1,867	3,073	2,336
Operation and maintenance	42	47	46
Depreciation and amortization	5	5	5
Taxes other than income taxes	1	2	1
Total expenses	1,915	3,127	2,388
Operating Income	$ 42	$ 52	$ 13
Mark-to-market gain (loss)	4	29	(2)
Throughput (in Bcf)	618	631	600
Number of customers at end of period (1)	18,099	17,964	17,510

(1) These numbers do not include approximately 9,700 and 8,800 natural gas customers as of December 31, 2014 and 2013, respectively, that are under residential and small commercial choice programs invoiced by their host utility.

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. In 2015, a $4 million mark-to-market benefit was recorded as compared to a benefit of $29 million in 2014. 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.

2014 Compared to 2013. Our Energy Services business segment reported operating income of $52 million for 2014 compared to $13 million for 2013. The increase in operating income of $39 million was primarily due to a $31 million increase from mark-to-market accounting for derivatives associated with certain natural gas purchases and sales used to lock in economic margins. A $29 million mark-to-market gain was incurred in 2014 compared to a charge of $2 million in 2013. The remaining increase in operating income was primarily due to improved margins resulting from weather-related optimization of existing gas transportation assets, reduced fixed costs and increased throughput and price volatility.

Interstate Pipelines

Substantially all of our Interstate Pipelines business segment was contributed to Enable on May 1, 2013. As a result, this segment did not report operating results for 2014 or 2015. Our equity method investment and related equity income in Enable are included in our Midstream Investments segment. The following table provides summary data of our Interstate Pipelines business segment for 2013:

	Year Ended December 31, 2013 (1)	
	(in millions, except throughput data)	
Revenues	$	186
Expenses:		
Natural gas		35
Operation and maintenance		51
Depreciation and amortization		20
Taxes other than income taxes		8
Total expenses		114
Operating Income	$	72
Equity in earnings of unconsolidated affiliates	$	7
Transportation throughput (in Bcf)		482

(1) Represents January 2013 through April 2013 results only.

Equity Earnings. This business segment recorded equity income of $7 million for the year ended December 31, 2013 from its interest in Southeast Supply Header, LLC (SESH), a jointly-owned pipeline. Beginning May 1, 2013, equity earnings related to our interest in SESH and Enable are reported as components of equity income in our Midstream Investments segment.

Field Services

Substantially all of our Field Services business segment was contributed to Enable on May 1, 2013. As a result, this segment did not report operating results for 2014 or 2015. Our equity method investment and related equity income in Enable are included in our Midstream Investments segment. The following table provides summary data of our Field Services business segment for 2013:

	Year Ended December 31, 2013 (1)	
	(in millions, except throughput data)	
Revenues	$	196
Expenses:		
Natural gas		54
Operation and maintenance		45
Depreciation and amortization		20
Taxes other than income taxes		4
Total expenses		123
Operating Income	$	73
Equity in earnings of unconsolidated affiliates	$	—
Gathering throughput (in Bcf)		252

(1) Represents January 2013 through April 2013 results only.

Midstream Investments

The following table summarizes the equity earnings (losses) of our Midstream Investments business segment for 2015, 2014 and 2013:

	Year Ended December 31,		
	2015 (2)	2014 (3)	2013 (4)
	(in millions)		
Enable (1)	$ (1,633)	$ 303	$ 173
SESH	—	5	8
Total	$ (1,633)	$ 308	$ 181

(1) These amounts include our share of Enable's impairment of goodwill and long-lived assets and the impairment of our equity method investment in Enable totaling $1,846 million during 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%.

(4) Represents our 58.3% limited partner interest in Enable and our 25.05% interest in SESH for the eight months ended December 31, 2013.

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 2016 include the following:

- capital expenditures of approximately $490 million;
- dividend to CenterPoint Energy of $363 million in connection with purchase of Enable's Series A Preferred Units;
- maturing senior notes of $325 million; and
- acquisition of the retail commercial and industrial businesses of Continuum for $77.5 million plus working capital.

We expect that anticipated 2016 cash needs will be met with borrowings under our credit facility, proceeds from commercial paper, anticipated cash flows from operations, distributions from Enable and Enable's redemption of $363 million of notes owed to us. 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 capital expenditures for 2015 and estimates of our capital expenditures for currently identified or planned projects for 2016 through 2020:

	2015	2016	2017	2018	2019	2020
	(in millions)					
Natural Gas Distribution	$ 601	$ 485	$ 470	$ 435	$ 430	$ 430
Energy Services	5	5	26	—	1	—
Total	$ 606	$ 490	$ 496	$ 435	$ 431	$ 430

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	2016	2017-2018	2019-2020	2021 and thereafter
	(in millions)				
Long-term debt	$ 2,353	$ 325	$ 550	$ 218	$ 1,260
Interest payments — long-term debt (1)	1,262	115	186	142	819
Short-term borrowings	40	40	—	—	—
Operating leases (2)	23	5	6	5	7
Benefit obligations (3)	—	—	—	—	—
Non-trading derivative liabilities	16	11	5	—	—
Other commodity commitments (4)	1,685	478	862	307	38
Total contractual cash obligations (5)	$ 5,379	$ 974	$ 1,609	$ 672	$ 2,124

(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, 2015. 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 13(c) to our consolidated financial statements.

(3) We expect to contribute approximately $6 million to our postretirement benefits plan in 2016 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 13(a) to our consolidated financial statements.

(5) This table does not include estimated future payments for expected future asset retirement obligations. These payments are primarily estimated to be incurred after 2021. We record a separate liability for the fair value of these asset retirement obligations which totaled $156 million as of December 31, 2015. See Note 3(c) to our consolidated financial statements.

Off-Balance Sheet Arrangements

Prior to the distribution of CenterPoint Energy’s ownership in Reliant Resources, Inc. (RRI) to its shareholders, we had guaranteed certain contractual obligations of what became RRI’s trading subsidiary. When the companies separated, RRI agreed to secure us against obligations under the guarantees RRI had been unable to extinguish by the time of separation. Pursuant to such agreement, as amended in December 2007, RRI (now GenOn Energy, Inc. (GenOn)) agreed to provide to us cash or letters of credit as security against our obligations under our remaining guarantees for demand charges under certain gas transportation agreements if and to the extent changes in market conditions expose us to a risk of loss on those guarantees based on an annual calculation, with any required collateral to be posted each December. The undiscounted maximum potential payout of the demand charges under these transportation contracts, which will be in effect until 2018, was approximately $27 million as of December 31, 2015. Based on market conditions in the fourth quarter of 2015 at the time the most recent annual calculation was made under the agreement, GenOn was not obligated to post any security. If GenOn should fail to perform the contractual obligations, we could have to honor our guarantee and, in such event, any collateral provided as security may be insufficient to satisfy our obligations.

We have also provided a guarantee of collection of $1.1 billion of Enable's senior notes due 2019 and 2024. This guarantee is subordinated to all our senior debt and is subject to automatic release on May 1, 2016.

The fair value of these guarantees is not material. Other than the guarantees described above and operating leases, we have no off-balance sheet arrangements.

Regulatory Matters

Texas Coast Rate Case. On March 27, 2015, NGD filed a Statement of Intent with each of the 49 cities and unincorporated areas within its Texas Coast service territory for a $6.8 million annual revenue increase. This increase was based on a rate base of $132.3 million and an ROE of 10.25%. On July 6, 2015, the parties agreed to a settlement providing for a $4.9 million annual increase to rates, an ROE of 10.0%, 54.5% equity and authorized overall rate of return of 8.23%. This settlement resolved six outstanding cases on appeal: one on remand at the Railroad Commission and five COSA appeals at the district court. The Railroad Commission unanimously approved the settlement on August 25, 2015. Rates were implemented in September 2015.

Houston, South Texas and Beaumont/East Texas GRIP. NGD's Houston, South Texas and Beaumont/East Texas Divisions each submitted annual GRIP filings on March 31, 2015. For the Houston Division, NGD asked that its GRIP filing to recover costs related to $46.4 million in incremental capital expenditures that were incurred in 2014 be operationally suspended for one year so as to ensure that earnings are more consistent with those currently approved. For the South Texas Division, the revised filing requested recovery of costs related to $22.2 million in incremental capital expenditures that were incurred in 2014. The increase in revenue requirements for this filing period is $4.0 million annually based on an authorized overall rate of return of 8.75%. For the Beaumont/East Texas Division, the GRIP filing requested recovery of costs related to $34.3 million in incremental capital expenditures that were incurred in 2014. The increase in revenue requirements for this filing period is $5.9 million annually based on an authorized overall rate of return of 8.51%. For the South Texas and Beaumont/East Texas Divisions, rates were implemented for certain customers in May 2015. For those areas in which the jurisdictional deadline was extended by regulatory action, the rates were implemented in July 2015 following approval by the Railroad Commission.

Oklahoma Performance Based Rate Change (PBRC). In March 2015, NGD made a PBRC filing for the 2014 calendar year proposing to increase revenues by $0.9 million. On November 4, 2015, the Oklahoma Corporation Commission approved the request.

Arkansas Energy Efficiency Cost Recovery (EECR). On March 31, 2015, NGD made an EECR filing with the APSC to recover $5.9 million for the 2015 program year. The purpose of the EECR is to recover NGD's estimated expenses and lost contributions to fixed cost for the energy efficiency programs approved by the APSC and administered either jointly or individually by NGD, plus a utility incentive earned for 2014, with adjustments for any over- or under-recovery from the prior period. The impact to customer bills is expected to be a small reduction due to actual program costs being less than estimated and a colder than normal year causing more EECR revenues than anticipated. New rates went into effect in July 2015.

Arkansas Rate Case. On August 17, 2015, NGD filed a Notice of Intent to File a general rate case with the APSC. The rate case was filed on November 10, 2015 seeking a $35.6 million increase in revenue requirement and a 10.3% ROE. A procedural schedule has been established with a hearing scheduled for July 12, 2016. A final determination by the APSC is expected in the third quarter of 2016.

Louisiana Rate Stabilization Plan (RSP). NGD made its 2015 Louisiana RSP filings with the Louisiana Public Service Commission (LPSC) on October 1, 2015. The North Louisiana Rider RSP filing shows a revenue deficiency of $1.0 million, and the South Louisiana Rider RSP filing shows a revenue deficiency of $1.5 million. Both 2015 RSP filings utilized the capital structure and ROE factors approved by the LPSC on September 23, 2015 discussed below. NGD began billing in December 2015 subject to a refund. NGD made its 2014 Louisiana RSP filings with the LPSC on October 1, 2014. The North Louisiana Rider RSP filing shows a revenue deficiency of $4.0 million, compared to the authorized ROE of 10.25%. The South Louisiana Rider RSP filing shows a revenue deficiency of $2.3 million, compared to the authorized ROE of 10.5%. NGD began billing the revised rates in December 2014, subject to refund. On November 19, 2014, NGD sought permission to amend the 2013 South Louisiana RSP filing to use a more representative capital structure and to adjust the filing's equity banding mechanism. On December 2, 2014, NGD sought permission for similar amendments to the 2013 North Louisiana RSP filing. On September 3, 2015, Uncontested Stipulated Settlement Agreements (Stipulations) between NGD and the LPSC Staff were filed in the 2013 Louisiana RSP dockets recommending a capital structure of 48% debt and 52% equity and ROE of 9.95%. On September 23, 2015, the LPSC issued orders approving the Stipulations and ordered refunds of the 2013 RSP over-collections plus 5% annual interest. Refunds for the 2013 North and South Louisiana RSP filings in the amount of approximately $0.9 million and $0.6 million, respectively, became effective in September 2015. The 2014 and 2015 Louisiana RSP filings are still awaiting final approval from the LPSC.

On February 20, 2015, the LPSC issued orders reducing rates and requiring refunds of over-collections plus 5% interest based on disallowance of certain costs included in the 2012 RSP filings. North Louisiana was required to adjust its 2012 RSP increase from $36,400 to $2,600. South Louisiana's 2012 RSP was further reduced by $0.1 million. New rates went into effect on February 23, 2015.

Mississippi Rate Regulation Adjustment (RRA). On May 1, 2015, NGD filed for a $2.5 million RRA with an adjusted ROE of 9.534% with the Mississippi Public Service Commission (MPSC). Additional filings were made under the Supplemental Growth Rider (SGR) of approximately $0.1 million with an ROE of 12% and the EECR rider of approximately $0.6 million. The MPSC approved the EECR and new rates were implemented on September 2, 2015. NGD and the Mississippi Commission Staff filed a Stipulation on December 1, 2015 in the RRA, which was approved by the MPSC on December 3, 2015. The stipulated revenue adjustment is $1.9 million with an ROE of 9.534%. The SGR was approved, as filed, on December 3, 2015. New rates for the RRA and the SGR were implemented in December of 2015.

Minnesota Conservation Cost Recovery Adjustment (CCRA) and CIP. On May 1, 2015, NGD filed applications with the MPUC for a CCRA and a Demand-Side Management Financial Incentive. NGD sought approval for a $2.3 million balance in its CIP Tracker, an $11.6 million financial incentive based on 2014 program performance, and an updated CCRA, to be effective on January 1, 2016. On August 11, 2015, the MPUC issued its order approving these requests.

Minnesota Rate Case. In August 2015, NGD filed a general rate case with the MPUC requesting an annual increase of $54.1 million. On September 10, 2015, the MPUC approved an interim increase of $47.8 million in revenues effective October 2, 2015, subject to a refund. The MPUC is expected to issue a final decision in mid-2016 with final rates effective by the end of 2016.

Other Matters

Credit Facility

As of February 12, 2016, we had the following revolving credit facility:

Execution Date	Size of Facility	Amount Utilized at February 12, 2016	Termination Date
	(in millions)		
September 9, 2011	$ 600	$ 18 (1)	September 9, 2019

(1) Represents outstanding commercial paper of $16 million and outstanding letters of credit of $2 million.

CERC Corp.'s $600 million revolving credit facility can be drawn at the London Interbank Offered Rate (LIBOR) plus 1.50% based on CERC Corp.'s current credit ratings. The revolving credit facility contains a financial covenant which limits our consolidated debt to an amount not to exceed 65% of our consolidated capitalization. As of December 31, 2015, our debt to capital ratio, as defined in its credit facility agreement, was 33.9%.

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 provides for customary fees, including commitment fees, administrative agent fees, fees in respect of letters of credit and other fees. The LIBOR borrowing spread 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.

CERC Corp.'s $600 million revolving credit facility backstops its $600 million commercial paper program. As of December 31, 2015, CERC Corp. had $219 million of outstanding commercial paper with a weighted average interest rate of 0.81%.

Securities Registered with the SEC

We have filed a shelf registration statement with the SEC registering an indeterminate principal amount of our senior debt securities.

Temporary Investments

As of February 12, 2016, 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. At February 12, 2016, 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 12, 2016, Moody's Investors Service, Inc. (Moody's), Standard & Poor's Ratings Services (S&P), a division of The McGraw-Hill Companies, and Fitch, Inc. (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-	Negative	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 $600 million 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, 2015, 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.

We and our subsidiaries purchase natural gas from one of our suppliers under supply agreements that contain an aggregate credit threshold of $140 million based on CERC Corp.'s S&P senior unsecured long-term debt rating of A-. Under these agreements, we may need to provide collateral if the aggregate threshold is exceeded or if the credit threshold is decreased due to a credit rating downgrade.

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 gas utilities throughout the central and eastern United States. In order 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. As of December 31, 2015, the amount posted as collateral aggregated approximately $87 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, 2015, unsecured credit limits extended to CES by counterparties aggregated $308 million, and $3 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 $152 million as of December 31, 2015. 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 $75 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 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.

On February 1, 2016, we announced that we are 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. There can be no assurances that this evaluation will result in any specific action, and we do not intend to disclose further developments on this initiative unless and until CenterPoint Energy's Board of Directors approves a specific action or as otherwise required.

Enable Midstream Partners

As of December 31, 2015, certain of the entities contributed to Enable by us were obligated on approximately $363 million of indebtedness owed to our wholly-owned subsidiary.

On January 28, 2016, CenterPoint Energy entered into a purchase agreement with Enable pursuant to which it agreed to purchase in a Private Placement an aggregate of 14,520,000 10% Series A Preferred Units for a cash purchase price of $25.00 per Series A Preferred Unit. The Private Placement closed on February 18, 2016. In connection with the Private Placement, Enable redeemed approximately $363 million of notes scheduled to mature in 2017 payable to our wholly-owned subsidiary. We made a dividend to CenterPoint Energy of $363 million and CenterPoint Energy used the dividend for its investment in the Series A Preferred Units.

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 (referred to as "available cash") within 45 days after the end of each quarter. On January 22, 2016, 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, 2015. Accordingly, CERC Corp. expects to receive a cash distribution of approximately $74 million from Enable in the first quarter of 2016 to be made with respect to CERC Corp.'s limited partner interest in Enable for the fourth quarter of 2015.

We recognized a loss of $1,633 million from our investment in Enable for the year ended December 31, 2015. This loss included 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 further discussion of the impairment, see Note 10 to our consolidated financial statements.

Dodd-Frank Swaps Regulation

We use derivative instruments such as physical forward contracts, swaps and options to mitigate the impact of changes in commodity prices and weather on our operating results and cash flows. Following enactment of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank) in July 2010, the Commodity Futures Trading Commission (CFTC) has promulgated regulations to implement Dodd-Frank's changes to the Commodity Exchange Act, including the definition of commodity-based swaps subject to those regulations. The CFTC regulations are intended to implement new reporting and record keeping requirements related to their swap transactions and a mandatory clearing and exchange-execution regime for various types, categories or classes of swaps, subject to certain exemptions, including the trade-option and end-user exemptions. Although we anticipate that most, if not all, of our swap transactions should qualify for an exemption to the clearing and exchange-execution requirements, we will still be subject to record keeping and reporting requirements. Other changes to the Commodity Exchange Act made as a result of Dodd-Frank and the CFTC's implementing regulations could increase the cost of entering into new swaps.

Weather Hedge

We have weather normalization or other rate mechanisms that mitigate the impact of weather on NGD in Arkansas, Louisiana, Mississippi, Minnesota and Oklahoma. NGD 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. We have 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. 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.

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 or in connection with the contractual obligations to a third party pursuant to which we are their guarantor;
- slower customer payments and increased write-offs of receivables due to higher gas prices or changing economic conditions;
- the outcome of litigation brought by and 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 this report.

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

Our revolving credit facility limits our debt as a percentage of our total capitalization to 65%.

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, 2015, we had recorded regulatory assets of $105 million and regulatory liabilities of $734 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 2015, 2014 and 2013. We did not record material impairments to long-lived assets, including intangibles during 2015, 2014, and 2013. We recorded impairments totaling $1,225 million to our equity method investments during 2015 and no impairment during 2014 and 2013. See Notes 9 and 10 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 2015 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 value of our Natural Gas Distribution reporting unit significantly exceeded the carrying value. The fair value of our Energy Services reporting unit exceeded the carrying value by approximately $150 million or approximately 50% excess fair value over the carrying value.

A key assumption in the income approach was the weighted average cost of capital of 5.6% and 5.9% applied in the valuation for Natural Gas Distributions and Energy Services, respectively. An increase in the discount rate to greater than 7.2%, a decline in long-term growth rate from 3% to 1.7%, or a decrease in the aggregate cash flows of greater than 33% could have individually triggered a step-two goodwill impairment evaluation for our Energy Services reporting unit in 2015.

Although there was not a goodwill asset impairment in our 2015 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 2015 annual test.

We determined in connection with our preparation of financial statements for the three months ended September 30, 2015 and December 31, 2015, 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 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 investment in Enable of $250 million and $975 million during the three months ended September 30, 2015 and December 31, 2015, respectively. 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 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 6(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 2016 is $37 million, of which we expect $27 million to impact pre-tax earnings, based on an expected return on plan assets of 6.25% and a discount rate of 4.40% as of December 31, 2015. We recorded pension expense of $26 million for the year ended December 31, 2015. 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, natural gas liquids and other energy commodities.

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

Interest Rate Risk

As of December 31, 2015, we had outstanding long-term debt and borrowings from affiliates that subject us to the risk of loss associated with movements in market interest rates.

Our floating-rate obligations aggregated $219 million and $529 million at December 31, 2015 and 2014, respectively. If the floating interest rates were to increase by 10% from December 31, 2015 rates, our combined interest expense would increase by less than $1 million annually.

As of both December 31, 2015 and 2014, we had outstanding fixed-rate debt aggregating $2.2 billion in principal amount and having a fair value of $2.4 billion and $2.5 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 11 to our consolidated financial statements). However, the fair value of these instruments would increase by approximately $68 million if interest rates were to decline by 10% from their levels at December 31, 2015. 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 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, 2015, the recorded fair value of our non-trading energy derivatives was a net asset of $53 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, 2015 levels would have decreased the fair value of our non-trading energy derivatives net asset by $6 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, 2015 and 2014, 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, 2015. 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, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 26, 2016

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

STATEMENTS OF CONSOLIDATED INCOME

	Year Ended December 31,		
	2015	2014	2013
		(in millions)	
Revenues	$ 4,527	$ 6,367	$ 5,522
Expenses:			
Natural gas	3,102	4,921	3,908
Operation and maintenance	741	751	828
Depreciation and amortization	227	206	230
Taxes other than income taxes	144	154	155
Total	4,214	6,032	5,121
Operating Income	313	335	401
Other Income (Expense):			
Interest and other finance charges	(137)	(141)	(154)
Equity in earnings (losses) of unconsolidated affiliates	(1,633)	308	188
Other, net	6	9	—
Total	(1,764)	176	34
Income (Loss) Before Income Taxes	(1,451)	511	435
Income tax expense (benefit)	(539)	188	371
Net Income (Loss)	$ (912)	$ 323	$ 64

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,		
	2015	2014	2013
	(in millions)		
Net income (loss)	$ (912)	$ 323	$ 64
Other comprehensive income (loss), net of tax:			
Adjustment to postretirement and other postemployment plans (net of tax of $6, $1 and $6)	8	(4)	6
Other comprehensive income (loss)	8	(4)	6
Comprehensive income (loss)	$ (904)	$ 319	$ 70

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,	
	2015	2014
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ —	$ 2
Accounts receivable, less bad debt reserve of $19 million and $23 million, respectively	350	595
Accrued unbilled revenue	183	262
Accounts and notes receivable — affiliated companies	8	18
Inventory	213	252
Non-trading derivative assets	89	99
Prepaid expenses and other current assets	61	90
Total current assets	904	1,318
Property, Plant and Equipment, Net	4,258	3,810
Other Assets:		
Goodwill	840	840
Non-trading derivative assets	36	32
Notes receivable — affiliated companies	363	363
Investment in unconsolidated affiliates	2,594	4,521
Other	158	160
Total other assets	3,991	5,916
Total Assets	$ 9,153	$ 11,044
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current Liabilities:		
Short-term borrowings	$ 40	$ 53
Current portion of long-term debt	325	—
Accounts payable	307	528
Accounts and notes payable — affiliated companies	39	228
Taxes accrued	63	67
Interest accrued	36	36
Customer deposits	80	80
Non-trading derivative liabilities	11	19
Other	158	137
Total current liabilities	1,059	1,148
Other Liabilities:		
Deferred income taxes, net	1,774	2,251
Non-trading derivative liabilities	5	1
Benefit obligations	89	111
Regulatory liabilities	734	669
Other	210	194
Total other liabilities	2,812	3,226
Long-Term Debt	2,028	2,469
Commitments and Contingencies (Note 13)		
Stockholder's Equity	3,254	4,201
Total Liabilities And Stockholder's Equity	$ 9,153	$ 11,044

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,		
	2015	2014	2013
	(in millions)		
Cash Flows from Operating Activities:			
Net income (loss)	$ (912)	$ 323	$ 64
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	227	206	230
Amortization of deferred financing costs	9	9	11
Deferred income taxes	(542)	178	357
Write-down of natural gas inventory	4	8	4
Equity in (earnings) losses of unconsolidated affiliates, net of distributions	1,779	(2)	(58)
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues, net	347	7	(220)
Accounts receivable/payable–affiliated companies	9	1	(2)
Inventory	35	(81)	(10)
Taxes receivable	—	18	(18)
Accounts payable	(221)	17	110
Fuel cost recovery	43	(41)	108
Interest and taxes accrued	58	(3)	33
Non-trading derivatives, net	(6)	(34)	4
Margin deposits, net	(4)	(79)	16
Other current assets	13	8	3
Other current liabilities	(11)	(6)	5
Other assets	(6)	(11)	(18)
Other liabilities	(5)	11	6
Other, net	(1)	6	10
Net cash provided by operating activities	816	535	635
Cash Flows from Investing Activities:			
Capital expenditures	(606)	(512)	(495)
Distributions from unconsolidated affiliates in excess of cumulative earnings	148	—	—
Investment in unconsolidated affiliates	—	(1)	—
Cash contribution to Enable	—	—	(38)
Other, net	6	—	(3)
Net cash used in investing activities	(452)	(513)	(536)
Cash Flows from Financing Activities:			
Increase (decrease) in short-term borrowings, net	(13)	10	5
Proceeds from (payments of) commercial paper, net	(122)	223	118
Proceeds from long-term debt	—	—	1,050
Payments of long-term debt	—	—	(525)
Cash paid for debt exchange	—	—	(5)
Dividends to parent	(43)	(405)	—
Increase (decrease) in notes payable–affiliated companies	(188)	150	(741)
Other, net	—	1	(1)
Net cash used in financing activities	(366)	(21)	(99)
Net Increase (Decrease) in Cash and Cash Equivalents	(2)	1	—
Cash and Cash Equivalents at Beginning of the Year	2	1	1
Cash and Cash Equivalents at End of the Year	$ —	$ 2	$ 1
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest, net of capitalized interest	$ 125	$ 128	$ 148
Income taxes (refunds), net	6	(1)	(5)
Non-cash transactions:			
Accounts payable related to capital expenditures	$ 37	$ 37	$ 21
Formation of Enable	—	—	4,252
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

	2015		2014		2013	
	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		2,416		2,416
Other		—		1		—
Balance, end of year		2,417		2,417		2,416
Retained Earnings						
Balance, beginning of year		1,783		1,865		1,801
Net income (loss)		(912)		323		64
Dividend to parent		(43)		(405)		—
Balance, end of year		828		1,783		1,865
Accumulated Other Comprehensive Income						
Balance, end of year:						
Adjustment to postretirement and other postemployment plans		9		1		5
Total accumulated other comprehensive income, end of year		9		1		5
Total Stockholder's Equity		$ 3,254		$ 4,201		$ 4,286

See Notes to Consolidated Financial Statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Background

CenterPoint Energy Resources Corp. (CERC Corp. and, together with its subsidiaries, CERC), which owns and operates natural gas distribution systems (NGD). A wholly-owned subsidiary of CERC Corp. offers variable and fixed-price physical natural gas supplies primarily to commercial and industrial customers and electric and gas utilities. As of December 31, 2015, CERC Corp. also owned approximately 55.4% of the limited partner interests in Enable, which owns, operates and develops natural gas and crude oil infrastructure assets.

CERC Corp. is an indirect, wholly-owned subsidiary of CenterPoint Energy, Inc. (CenterPoint Energy), a public utility holding company.

For a description of CERC's reportable business segments, see Note 15.

(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 May 2013, CenterPoint Energy, OGE Energy Corp. (OGE) and affiliates of ArcLight Capital Partners, LLC (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 accretion 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 variable interest entity (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.

As of December 31, 2015, CERC Corp. and OGE held approximately 55.4% and 26.3%, respectively, of the limited partner interests in Enable. Enable is controlled jointly by CERC Corp. and OGE, and each own 50% of the management rights in the general partner of Enable.

As of December 31, 2015, 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 45 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.

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's rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. As of December 31, 2015 and 2014, these removal costs of $632 million and $605 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 asset retirement obligations has been reclassified from a regulatory liability to an asset retirement liability in accordance with accounting guidance for asset retirement obligations.

(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 Allowance for Funds Used During Construction

Interest and allowance for funds used during construction (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. During 2015, 2014 and 2013, CERC capitalized interest and AFUDC of $2 million, $1 million and $1 million, respectively.

(h) Income Taxes

CERC is included in the consolidated income tax returns of CenterPoint Energy. CERC calculates its income tax provision on a separate return basis under 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.

(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 2015, 2014 and 2013 was $19 million, $20 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 2015, 2014 and 2013, CERC recorded $4 million, $8 million and $4 million, respectively, in write-downs of natural gas inventory to the lower of average cost or market.

	December 31,	
	2015	2014
	(in millions)	
Materials and supplies	$ 45	$ 41
Natural gas	168	211
Total inventory	$ 213	$ 252

(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 Financial Accounting Standards Board (FASB) issued Accounting Standards Update 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 variable interest entities (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. ASU 2015-02 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. CERC does not believe that ASU 2015-02 will have a material impact on its financial position, results of operations, cash flows and disclosures.

In April 2015, the FASB issued Accounting Standards Update 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 will adopt ASU 2015-03 retrospectively on January 1, 2016, which will result in a reduction of both other long-term assets and long-term debt on its Consolidated Balance Sheets. CERC had debt issuance costs of $15 million and $18 million included in other long-term assets on its Consolidated Balance Sheets as of December 31, 2015 and 2014, respectively.

In April 2015, the FASB issued Accounting Standards Update No. 2015-05, *Intangibles-Goodwill and Other-Internal-Use Software* (*Subtopic 350-40*) (ASU 2015-05). ASU 2015-05 provides guidance to customers about whether a cloud computing arrangement includes a software license. If a cloud computing arrangement includes a software license, the customer should account for the software license element of the arrangement consistent with the acquisition of other software licenses. If a cloud computing arrangement does not include a software license, the customer should account for the arrangement as a service contract. The guidance will not change a customer's accounting for service contracts. ASU 2015-05 is effective for fiscal years, and interim periods within the fiscal years, beginning after December 15, 2015 and may be adopted either prospectively or retrospectively. CERC will adopt ASU 2015-05 on January 1, 2016. CERC does not believe that ASU 2015-05 will have a material impact on its financial position, results of operations, cash flows and disclosures.

In May 2014, the FASB issued Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers (Topic 606)* (ASU 2014-09), which supersedes most current revenue recognition guidance. ASU 2014-09 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. ASU 2014-09 was initially effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. Early adoption is not permitted, and entities have the option of using either a full retrospective or a modified retrospective adoption approach. In August 2015, the FASB issued Accounting Standard Update No. 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date*, which delays the effective date of ASU 2014-09 by one year. CERC is currently evaluating the impact that ASU 2014-09 will have on its financial position, results of operations, cash flows and disclosures, and will adopt ASU 2014-09 on January 1, 2018 as permitted by the new guidance.

In July 2015, the FASB issued Accounting Standards Update No. 2015-11, *Inventory (Topic 330) Simplifying the Measurement of Inventory* (ASU 2015-11). ASU 2015-11 changes the subsequent measurement guidance for inventory accounted for using methods other than the last in, first out (LIFO) and Retail Inventory methods. Companies will subsequently measure inventory at the lower of cost and net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. Subsequent measurement is unchanged for inventory measured using LIFO or the retail inventory method. ASU 2015-11 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016, with early adoption permitted. CERC does not believe that ASU 2015-11 will have a material impact on its financial position, results of operations, cash flows and disclosures.

In November 2015, the FASB issued Accounting Standards Update No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17). ASU 2015-17 requires deferred tax liabilities and assets be classified as noncurrent in a classified statement of financial position. CERC adopted ASU 2015-17 retrospectively starting with fiscal year 2015. As such, certain prior period amounts have been reclassified to conform to the current presentation. In the Consolidated Balance Sheet as of

December 31, 2014, CERC reclassified $1 million from current deferred income tax assets to reduce deferred income taxes within non-current liabilities. See Note 12 for additional information.

Management believes that other recently issued standards, which are not yet effective, will not have a material impact on CenterPoint Energy'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 at December 31, 2015 and 2014 were $31 million and $19 million, respectively, of margin deposits and $12 million and $45 million, respectively of under-recovered gas cost. Included in other current liabilities on the Consolidated Balance Sheets at December 31, 2015 and 2014 were $55 million and $37 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 (Years)	December 31, 2015	December 31, 2014
		(in millions)	
Natural Gas Distribution	32	$ 5,762	$ 5,235
Energy Services	27	86	84
Other property	10	50	45
Total		5,898	5,364
Accumulated depreciation and amortization:			
Natural Gas Distribution		1,575	1,493
Energy Services		34	31
Other property		31	30
Total accumulated depreciation and amortization		1,640	1,554
Property, plant and equipment, net		$ 4,258	$ 3,810

(b) Depreciation and Amortization

The following table presents depreciation and amortization expense for 2015, 2014 and 2013:

	Year Ended December 31, 2015	2014	2013
		(in millions)	
Depreciation expense	$ 211	$ 195	$ 218
Amortization expense	16	11	12
Total depreciation and amortization expense	$ 227	$ 206	$ 230

(c) Asset Retirement Obligations

A reconciliation of the changes in the asset retirement obligation (ARO) liability is as follows:

	December 31,	
	2015	2014
	(in millions)	
Beginning balance	$ 139	$ 101
Accretion expense	5	4
Revisions in estimates of cash flows	12	34
Ending balance	$ 156	$ 139

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 $12 million in the ARO from the revision of estimate in 2015 is primarily attributable to a reduction in the estimated service lives of steel and plastic pipe. The decrease of $34 million in the ARO from the revision of estimate in 2014 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, 2015 or 2014.

(4) Goodwill

Goodwill by reportable business segment as of both December 31, 2015 and 2014 are as follows:

	(in millions)
Natural Gas Distribution	$ 746
Energy Services (1)	83
Other	11
Total	$ 840

(1) Amounts presented are net of 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 2015 and 2014 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, 2015 and 2014.

(5) Regulatory Accounting

The following is a list of regulatory assets/liabilities reflected on CERC's Consolidated Balance Sheets as of December 31, 2015 and 2014:

	December 31,	
	2015	2014
	(in millions)	
Regulatory assets in other long-term assets (1) (2)	$ 105	$ 103
Regulatory liabilities	(734)	(669)
Net	$ (629)	$ (566)

(1) Regulatory assets that are not earning a return were not material at December 31, 2015 or 2014.

(2) 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 $5 million as of December 31, 2015 were not earning a return.

(6) 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 $24 million, $27 million and $29 million for the years ended December 31, 2015, 2014 and 2013, 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 $2 million for each of the years ended December 31, 2015, 2014 and 2013, 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 common stock, to have dividends reinvested in additional shares or to receive dividend payments in cash on any investment in CenterPoint Energy common stock, and to transfer all or part of their investment in CenterPoint Energy 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 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 common stock.

The savings plan has significant holdings of CenterPoint Energy common stock. As of December 31, 2015, 16,942,974 shares of CenterPoint Energy's common stock were held by the savings plan, which represented approximately 17% of its investments. Given the concentration of the investments in CenterPoint Energy's 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 $14 million, $20 million and $19 million for the years ended December 31, 2015, 2014 and 2013, 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. Under plan amendments effective in early 1999, healthcare benefits for future retirees were changed to limit employer contributions for medical coverage. 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,		
	2015	2014	2013
		(in millions)	
Service cost — benefits earned during the period	$ 1	$ 1	$ 1
Interest cost on accumulated benefit obligation	5	5	5
Expected return on plan assets	(1)	(1)	(1)
Amortization of prior service cost	1	1	1
Amortization of net loss	1	1	2
Net postretirement benefit cost	$ 7	$ 7	$ 8

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

	Year Ended December 31,		
	2015	2014	2013
Discount rate	3.90%	4.75%	3.90%
Expected return on plan assets	4.05%	3.10%	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 2015 and 2014. The measurement dates for plan assets and obligations were December 31, 2015 and 2014.

	December 31,	
	2015	2014
	(in millions, except for actuarial assumptions)	
Change in Benefit Obligation		
Accumulated benefit obligation, beginning of year	$ 126	$ 116
Service cost	1	1
Interest cost	5	5
Benefits paid	(12)	(13)
Participant contributions	4	4
Medicare reimbursement	1	2
Plan amendment	(5)	1
Curtailment	—	(2)
Actuarial (gain) loss	(19)	12
Accumulated benefit obligation, end of year	$ 101	$ 126
Change in Plan Assets		
Plan assets, beginning of year	$ 26	$ 26
Benefits paid	(12)	(13)
Employer contributions	7	8
Participant contributions	4	4
Actual investment return	—	1
Plan assets, end of year	$ 25	$ 26
Amounts Recognized in Balance Sheets		
Current liabilities-other	$ (6)	$ (7)
Other liabilities-benefit obligations	(70)	(93)
Net liability, end of year	$ (76)	$ (100)
Actuarial Assumptions		
Discount rate	4.35%	3.90%
Expected long-term return on assets	3.95%	4.00%
Healthcare cost trend rate assumed for the next year - Pre 65	6.00%	7.25%
Healthcare cost trend rate assumed for the next year - Post 65	5.50%	8.50%
Prescription cost trend rate assumed for the next year	11.00%	6.50%
Rate to which the cost trend rate is assumed to decline (ultimate trend rate)	5.00%	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

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 6.00% and 5.50% for the pre-65 and post-65 retirees during 2016, respectively, and the prescription cost is assumed to increase 11.00% during 2016, after which these rates decrease until reaching the ultimate trend rate of 5.00% in 2024.

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

	Year Ended December 31,	
	2015	2014
	(in millions)	
Beginning Balance	$ 1	$ 5
Other comprehensive income (loss) before reclassifications (1)	13	(5)
Amounts reclassified from accumulated other comprehensive income:		
Actuarial gains (2)	1	—
Total reclassifications from accumulated other comprehensive income	1	—
Tax expense	(6)	1
Net current period other comprehensive income (loss)	8	(4)
Ending Balance	$ 9	$ 1

(1) Total other comprehensive income related to the re-measurement 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,	
	2015	2014
	(in millions)	
Unrecognized actuarial loss	$ 3	$ 13
Unrecognized prior service cost (credit)	(1)	2
Total recognized in accumulated other comprehensive loss	2	15
Less: deferred tax benefit (1)	(11)	(16)
Net amount recognized in accumulated other comprehensive income	$ (9)	$ (1)

(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 2015 are as follows:

	Postretirement Benefits
	(in millions)
Net loss	$ 10
Amortization of prior service cost	3
Total recognized in other comprehensive loss	$ 13

The total expense recognized in net periodic costs and other comprehensive gains was $2 million for postretirement benefits for the year ended December 31, 2015.

CERC does not expect to recognize any amounts in accumulated other comprehensive loss as components of net periodic benefit cost during 2016.

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	$ 2	$ 2
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, 2015:

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, 2015 and 2014, by asset category are as follows:

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

	Fair Value Measurements as of December 31, 2014			
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(in millions)			
Mutual funds (1)	$ 26	$ 26	$ —	$ —
Total	$ 26	$ 26	$ —	$ —

(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 $6 million to its postretirement benefits plan in 2016. The following benefit payments are expected to be made by the postretirement benefit plan:

	Postretirement Benefit Plan	
	Benefit Payments	Medicare Subsidy Receipts
	(in millions)	
2016	$ 10	$ (2)
2017	10	(2)
2018	10	(2)
2019	11	(2)
2020	11	(3)
2021-2025	56	(17)

(d) Postemployment Benefits

CERC participates in CenterPoint Energy's plan that provides postemployment benefits for 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 $4 million, $2 million and $1 million for the years ended December 31, 2015, 2014 and 2013, respectively. Amounts relating to postemployment benefits included in Benefit Obligations in the accompanying Consolidated Balance Sheets as of December 31, 2015 and 2014, were $14 million and $12 million, respectively.

(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 2015, 2014 and 2013, 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, 2015 and 2014 were $3 million.

(f) Other Employee Matters

As of December 31, 2015, approximately 34% of CERC's employees were covered by collective bargaining agreements. Two collective bargaining agreements with Professional Employees International Union Local 12, which collectively cover approximately 4% of CERC's employees, are scheduled to expire in March and May of 2016. CERC believes it has good relationships with these bargaining units and expects to negotiate new agreements in 2016.

(7) 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 money pool borrowings of $-0- and $188 million as of December 31, 2015 and 2014, respectively, which are included in accounts and notes payable — affiliated companies in the Consolidated Balance Sheets.

For the years ended December 31, 2015, 2014 and 2013, CERC had affiliate related net interest income (expense) of less than $(1) million, less than $1 million and $(2) million, respectively.

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. CenterPoint Houston 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, radio communications, data circuit management and field operations. Additionally, CERC provides certain services to CenterPoint Houston. 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,		
	2015	2014	2013
	(in millions)		
Corporate service charges	$ 118	$ 115	$ 105
Charges from CenterPoint Houston for services provided	18	17	21
Billings to CenterPoint Houston for services provided	(6)	(5)	(9)
	$ 130	$ 127	$ 117

Dividends of $43 million and $405 million were paid to the parent in 2015 and 2014. No dividends were paid to the parent in 2013.

See Note 10 for related party transactions with Enable.

(8) 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 manage physical commodity price risk and does not engage in proprietary or speculative commodity trading. 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 both 2013–2014 and 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, 2015, 2014 and 2013, CERC recognized losses of $4 million, $10 million and $16 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, 2015 and 2014, while the last table provides a breakdown of the related income statement impacts for the years ending December 31, 2015 and 2014.

Fair Value of Derivative Instruments

		December 31, 2015	
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	$ 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 billion cubic feet (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 offset 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.

Fair Value of Derivative Instruments

Total derivatives not designated as hedging instruments	Balance Sheet Location	Derivative Assets Fair Value	Derivative Liabilities Fair Value
		December 31, 2014	
		(in millions)	
Natural gas derivatives (1) (2) (3)	Current Assets: Non-trading derivative assets	$ 101	$ 1
Natural gas derivatives (1) (2) (3)	Other Assets: Non-trading derivative assets	32	—
Natural gas derivatives (1) (2) (3)	Current Liabilities: Non-trading derivative liabilities	14	83
Natural gas derivatives (1) (2) (3)	Other Liabilities: Non-trading derivative liabilities	2	18
Total		$ 149	$ 102

(1) The fair value shown for natural gas contracts is comprised of derivative gross volumes totaling 804 Bcf or a net 60 Bcf long position. Of the net long position, basis swaps constitute 127 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 $111 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, offset by collateral netting of $64 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

	Gross Amounts Recognized (1)	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amount Presented in the Consolidated Balance Sheets (2)
	December 31, 2014		
	(in millions)		
Current Assets: Non-trading derivative assets	$ 115	$ (16)	$ 99
Other Assets: Non-trading derivative assets	34	(2)	32
Current Liabilities: Non-trading derivative liabilities	(84)	65	(19)
Other Liabilities: Non-trading derivative liabilities	(18)	17	(1)
Total	$ 47	$ 64	$ 111

(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.

For CERC's price stabilization activities of the Natural Gas Distribution business segment, the settled costs of derivatives are ultimately recovered through purchased gas adjustments. Accordingly, the net unrealized gains and losses associated with these contracts are recorded as net regulatory assets. Realized and unrealized gains and losses on other 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, 2015	2014	2013
		(in millions)		
Natural gas derivatives	Gains (Losses) in Revenue	$ 134	$ 35	$ 11
Natural gas derivatives (1)	Gains (Losses) in Expense: Natural Gas	(105)	11	10
Total		$ 29	$ 46	$ 21

(1) The Gains (Losses) in Expense: Natural Gas includes $-0- and $2 million during the years ended December 31, 2015 and 2014, respectively, related to physical forwards purchased from Enable.

(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 Standard & Poor's Ratings Services or Moody's Investors Service, Inc. 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 at December 31, 2015 and 2014 was $3 million and $2 million, respectively. CERC posted no assets as collateral towards derivative instruments that contain credit risk contingent features at either December 31, 2015 or 2014. If all derivative contracts (in a net liability position) containing credit risk contingent features were triggered at both December 31, 2015 and 2014, $2 million 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, 2015 and 2014:

	December 31, 2015		December 31, 2014	
	Investment Grade(1)	Total	Investment Grade(1)	Total
	(in millions)			
Energy marketers	$ 4	$ 10	$ 2	$ 4
Financial institutions	—	—	—	—
End users (2)	2	115	2	127
Total	$ 6	$ 125	$ 4	$ 131

(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.

(9) 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, 2015, 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 $1.36 to $3.29 per one million British thermal units (Btu)) 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 82%) 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, 2015, 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 as of December 31, 2015 and 2014, and indicate the fair value hierarchy of the valuation techniques utilized by CERC to determine such fair value.

	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 as of December 31, 2015
			(in millions)		
Assets					
Corporate equities	$ 2	$ —	$ —	$ —	$ 2
Investments, including money market funds	11	—	—	—	11
Natural gas derivatives (2)	4	115	21	(15)	125
Total assets	$ 17	$ 115	$ 21	$ (15)	$ 138
Liabilities					
Natural gas derivatives (2)	$ 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) Natural gas derivatives include no material amounts related to physical forward transactions with Enable.

	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 as of December 31, 2014
			(in millions)		
Assets					
Corporate equities	$ 2	$ —	$ —	$ —	$ 2
Investments, including money market funds	11	—	—	—	11
Natural gas derivatives (2)	7	122	20	(18)	131
Total assets	$ 20	$ 122	$ 20	$ (18)	$ 144
Liabilities					
Natural gas derivatives	$ 22	$ 77	$ 3	$ (82)	$ 20
Total liabilities	$ 22	$ 77	$ 3	$ (82)	$ 20

(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 $64 million posted with the same counterparties.

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

The following tables present 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,		
	2015	2014	2013
		(in millions)	
Beginning balance	$ 17	$ 3	$ 2
Total gains	7	14	3
Total settlements	(12)	1	(3)
Transfers out of Level 3	(1)	—	—
Transfers into Level 3	1	(1)	1
Ending balance (1)	$ 12	$ 17	$ 3
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	$ 6	$ 16	$ 2

(1) During 2015, 2014 and 2013, CenterPoint Energy did not have significant Level 3 purchases or sales.

Items Measured at Fair Value on a Nonrecurring Basis

Based on the sustained low Enable common unit price and further declines in such price during the three months ended September 30, 2015 and December 31, 2015, respectively, as well as the market outlook for continued depressed crude oil and natural gas prices impacting the midstream oil and gas industry, CenterPoint Energy determined in connection with its preparation of financial statements for the three months ended September 30, 2015 and December 31, 2015, respectively, that an other than temporary decrease in the value of its investment in Enable had occurred. The impairment analyses compared the estimated fair value of CenterPoint Energy’s 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.

Both of these approaches incorporate significant estimates and assumptions, including:

Market Approach

- volume weighted average quoted price of Enable's common units;
- recent market transactions of comparable companies; and
- EBITDA to total enterprise multiples for comparable companies.

Income Approach

- Enable's forecasted cash distributions;
- projected cash flows of incentive distribution rights;
- forecasted growth rate of Enable's cash distributions; and
- determination of the cost of equity, including market risk premiums.

Weighting of the different approaches

Significant unobservable inputs used include the growth rate applied to the projected cash distributions beyond 2020 and the discount rate used to determine the present value of the estimated future cash flows. CERC based its assumptions on projected financial information that CERC believes is reasonable; however, actual results may differ materially from those projections. Based on the significant unobservable estimates and assumptions required, CenterPoint Energy concluded that the fair value estimate should be classified as a Level 3 measurement within the fair value hierarchy.

As a result of the analysis, CERC recorded other than temporary impairments on its investment in Enable of $250 million and $975 million during the three months ended September 30, 2015 and December 31, 2015, respectively. See Note 10 for further discussion of the impairment. As of December 31, 2014, 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. 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 Condensed 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, 2015		December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Financial assets:				
Notes receivable - affiliated companies	$ 363	$ 356	$ 363	$ 362
Financial liabilities:				
Long-term debt	$ 2,353	$ 2,551	$ 2,469	$ 2,772

(10) Unconsolidated Affiliates

On May 1, 2013 (the Closing Date) CERC Corp., OGE Energy Corp. (OGE) and ArcLight Capital Partners, LLC (ArcLight) closed on the formation of Enable, and CERC recorded an equity method investment in Enable at the historical cost of the contributed net assets. See Note 2 for further 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, 2015, CERC Corp.'s guarantee of collection of Enable’s $1.1 billion senior notes due 2019 and 2024 (Guaranteed Senior Notes) and other guarantees discussed in Note 13, and outstanding current accounts receivable from Enable. As of December 31, 2015, certain of the entities contributed to Enable by CERC Corp. were obligated on approximately $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%. Enable redeemed such notes scheduled to mature in 2017 in connection with the private placement discussed further in Note 16. CERC recorded interest income of $8 million during both the year ended December 31, 2015 and 2014, and had interest receivable from Enable of $4 million as of both December 31, 2015 and 2014, on its notes receivable from Enable.

Effective on the Closing Date, CenterPoint Energy and Enable entered into a Services Agreement, Employee Transition Agreement, Transitional Seconding Agreement and other agreements (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 ending on April 30, 2016, after which such services continue on a year-to-year basis unless terminated by Enable with at least 90 days’ notice. CERC expects to provide certain services to Enable following the completion of the initial term.

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. See Note 6 for additional information.

On April 16, 2014, Enable completed its initial public offering (IPO) of 28,750,000 common units, at a price of $20.00 per unit, which included 3,750,000 common units sold by ArcLight pursuant to an over-allotment option that was fully exercised by the underwriters. Enable received $464 million in net proceeds from the sale of the units, after deducting underwriting fees, structuring fees and other offering costs. In connection with Enable’s IPO, a portion of CERC’s common units were converted into subordinated units, as discussed further below. Subsequent to the IPO, Enable continues to be controlled jointly by CERC and OGE.

As a result of Enable’s IPO, CERC’s limited partner interest in Enable was reduced from approximately 58.3% to approximately 54.7%. CERC accounted for the dilution of its investment in Enable as a result of Enable’s IPO as a failed partial sale of in-substance real estate. CERC did not receive any cash from Enable’s IPO and, as such, CERC did not recognize a gain or loss. CERC’s basis difference in Enable was reduced for the impact of the Enable IPO.

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 Southeast Supply Header, LLC (SESH) retained by CERC on the Closing Date, under which CERC would contribute its retained interest in SESH, in exchange for a specified number of limited partner common units in Enable and a cash payment, payable either from CERC to Enable or from Enable to CERC, to the extent of changes in the value of SESH subject to certain restrictions. Specifically, the rights were exercisable with respect to (1) a 24.95% interest in SESH, which closed on May 30, 2014 and (2) a 0.1% interest in SESH, which closed on June 30, 2015.

CERC billed Enable for reimbursement of transition services, including the costs of seconded employees, $16 million and $163 million during the years ended December 31, 2015 and 2014, respectively, under the Transition Agreements. Actual transition services costs are recorded net of reimbursements received from Enable. CERC had accounts receivable from Enable of $3 million and $28 million as of December 31, 2015 and 2014, respectively, for amounts billed for transition services, including the cost of seconded employees.

CERC incurred natural gas expenses, including transportation and storage costs, of $117 million and $130 million during the year ended December 31, 2015 and 2014, respectively, for transactions with Enable. CERC had accounts payable to Enable of $11 million and $23 million at December 31, 2015 and 2014, respectively, from such transactions.

As of December 31, 2015, CERC held an approximate 55.4% limited partner interest in Enable consisting of 94,151,707 common units and 139,704,916 subordinated units. As of December 31, 2015, CERC and OGE each own a 50% management interest in the general partner of Enable and a 40% and 60% interest, respectively, in the incentive distribution rights held by the general partner.

CERC recognized a loss of $1,633 million from its investment in Enable as of December 31, 2015. This loss included impairment charges totaling $1,846 million composed of CERC’s impairment of its investment in Enable of $1,225 million and CERC’s share, $621 million, of impairment charges Enable recorded for goodwill and long-lived assets.

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 three months ended September 30, 2015 and December 31, 2015, respectively, as well as the market outlook for continued depressed crude oil and natural gas prices impacting the midstream oil and gas industry, CERC determined in connection with its preparation of financial statements for the three months ended September 30, 2015 and December 31, 2015, that an other than temporary decrease in the value of its investment in Enable had occurred. CERC wrote down the value of its investment in Enable to its estimated fair value which resulted in impairment charges of $250 million as of September 30, 2015 and $975 million as of 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 9 for further discussion of the determination of fair value of CERC's investment in Enable.

Investment in Unconsolidated Affiliates:

	Year Ended December 31,	
	2015	2014
	(in millions)	
Enable	$ 2,594	$ 4,520
SESH (1)	—	1
Total	$ 2,594	$ 4,521

(1) CERC disposed of its remaining interest in SESH on June 30, 2015.

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

	Year Ended December 31,		
	2015	2014	2013
	(in millions)		
Enable	$ (1,633)	$ 303	$ 173
SESH (1)	—	5	15
Total	$ (1,633)	$ 308	$ 188

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

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

	Year Ended December 31,		
	2015	2014	2013
	(in millions)		
Operating revenues	$ 2,418	$ 3,367	$ 2,123
Cost of sales, excluding depreciation and amortization	1,097	1,914	1,241
Impairment of goodwill and other long-lived assets	1,134	8	12
Operating income (loss)	(712)	586	322
Net income (loss) attributable to Enable	(752)	530	289
Reconciliation of Equity in Earnings (Losses), net:			
CERC's interest	$ (416)	$ 298	$ 168
Basis difference amortization (1)	8	5	5
Impairment of CERC's equity method investment in Enable	(1,225)	—	—
CERC's equity in earnings (losses), net (2)	$ (1,633)	$ 303	$ 173

(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 CERC's share of Enable's impairment of goodwill and long-lived assets and the impairment of CERC's equity method investment in Enable totaling $1,846 million during 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,	
	2015	2014
	(in millions)	
Current assets	$ 381	$ 438
Non-current assets	10,857	11,399
Current liabilities	615	671
Non-current liabilities	3,092	2,343
Non-controlling interest	12	31
Enable partners' capital	7,519	8,792
Reconciliation of Investment in Enable:		
CERC's ownership interest in Enable partners' capital	$ 4,163	$ 4,869
CERC's basis difference	(1,569)	(349)
CERC's investment in Enable	$ 2,594	$ 4,520

Distributions Received from Unconsolidated Affiliates:

	Year Ended December 31,		
	2015	2014	2013
		(in millions)	
Enable	$ 294	$ 298	$ 106
SESH (1)	—	7	23
Total	$ 294	$ 305	$ 129

(1) CERC contributed a 24.95% interest in SESH to Enable on each of May 1, 2013 and May 30, 2014 and its remaining interest in SESH to Enable on June 30, 2015.

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

	December 31, 2015		December 31, 2014	
	Long-Term	Current (1)	Long-Term	Current (1)
		(in millions)		
Short-term borrowings:				
Inventory financing	$ —	$ 40	$ —	$ 53
Total short-term borrowings	—	40	—	53
Long-term debt:				
Senior notes 4.50% to 6.625% due 2016 to 2041	1,843	325	2,168	—
Commercial paper (2)	219	—	341	—
Unamortized discount and premium	(34)	—	(40)	—
Total long-term debt	2,028	325	2,469	—
Total debt	$ 2,028	$ 365	$ 2,469	$ 53

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

(2) 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 poor borrowings, please see Note 7.

(a) Short-term Borrowings

Inventory Financing. NGD has asset management agreements associated with its utility distribution service in Arkansas, north Louisiana and Oklahoma that extend through 2019. 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 a financing and had an associated principal obligation of $40 million and $53 million as of December 31, 2015 and 2014, respectively.

(b) Long-term Debt

Revolving Credit Facility. As of December 31, 2015 and 2014, CERC had the following revolving credit facility and utilization of such facility:

	December 31, 2015			December 31, 2014		
Size of Facility	Loans	Letters of Credit	Commercial Paper	Loans	Letters of Credit	Commercial Paper
(in millions)						
$ 600	$ —	$ 2	$ 219 (1)	$ —	$ —	$ 341 (1)

(1) Weighted average interest rate was 0.81% and 0.68% as of December 31, 2015 and 2014, respectively.

CERC Corp.'s $600 million revolving credit facility, which is scheduled to terminate on September 9, 2019, can be drawn at the London Interbank Offered Rate plus 1.50% based on CERC Corp.'s current credit ratings. The revolving credit facility contains a financial covenant which limits CERC's consolidated debt to an amount not to exceed 65% of CERC's consolidated capitalization. As of December 31, 2015, CERC's debt to capital ratio, as defined in its credit facility agreement, was 33.9%.

CERC Corp. was in compliance with all financial covenants in its revolving credit facility as of December 31, 2015.

Maturities. CERC's consolidated maturities of long-term debt are $325 million in 2016, $250 million in 2017, $300 million in 2018, $219 million in 2019 and $-0- in 2020.

(12) Income Taxes

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

	Year Ended December 31,		
	2015	2014	2013
	(in millions)		
Current income tax expense:			
Federal	$ —	$ —	$ 5
State	3	10	9
Total current expense	3	10	14
Deferred income tax expense (benefit):			
Federal	(488)	171	350
State	(54)	7	7
Total deferred expense (benefit)	(542)	178	357
Total income tax expense (benefit)	$ (539)	$ 188	$ 371

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,		
	2015	2014	2013
	(in millions)		
Income (loss) before income taxes	$ (1,451)	$ 511	$ 435
Federal statutory income tax rate	35%	35%	35%
Expected federal income tax expense (benefit)	(508)	179	152
Increase (decrease) in tax expense resulting from:			
State income tax expense, net of federal income tax	(33)	11	23
Decrease in settled and uncertain income tax positions	—	—	(2)
Tax effect related to the formation of Enable Midstream Partnership	—	—	198
Other, net	2	(2)	—
Total	(31)	9	219
Total income tax expense (benefit)	$ (539)	$ 188	$ 371
Effective tax rate	37.1%	36.8%	85.3%

In 2013, CERC recorded a deferred tax expense of $225 million at the formation of Enable related to the book-to-tax basis difference for contributed non-tax deductible goodwill and recognized a tax benefit of $27 million associated with the remeasurement of state deferred taxes at formation. In addition, CERC recognized a tax benefit of $2 million based on the settlement with the Internal Revenue Service (IRS) of outstanding tax claims for the 2002 and 2003 tax years.

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

	December 31,	
	2015	2014
	(in millions)	
Deferred tax assets:		
Benefits and compensation	$ 39	$ 48
Loss and credit carryforwards	388	326
Asset retirement obligations	59	52
Other	39	28
Valuation allowance	(2)	(2)
Total deferred tax assets	523	452
Deferred tax liabilities:		
Property, plant, and equipment	929	803
Investment in unconsolidated affiliates	1,277	1,788
Regulatory assets/liabilities, net	—	13
Other	91	99
Total deferred tax liabilities	2,297	2,703
Net deferred tax liabilities	$ 1,774	$ 2,251

Effective December 31, 2015, all deferred taxes for 2014 and 2015 are classified as noncurrent. See Note 2.

CERC is included in the consolidated income tax returns of CenterPoint Energy. CERC calculates its income tax provision on a separate return basis under a tax sharing agreement with CenterPoint Energy.

Tax Attribute Carryforwards and Valuation Allowance. CERC has $946 million of federal net operating loss carryforwards which expire between 2031 and 2035, $23 million of federal capital loss carryforwards which expire between 2018 and 2019, and $1 million of charitable contribution carryforwards which expire between 2018 and 2020.

CERC has $905 million of state net operating loss carryforwards which expire between 2016 and 2035, $7 million of state tax credits which do not expire, and $244 million of state capital loss carryforwards which expire in 2017. Management has established a valuation allowance of $2 million net of federal tax on certain state net operating losses and the full amount of the state capital loss carryforwards. The valuation allowance was established based upon management's evaluation that certain state carryforwards may not be fully realized.

Uncertain Income Tax Positions. The following table reconciles the beginning and ending balance of CERC's unrecognized tax benefits (expenses):

	December 31,		
	2015	2014	2013
		(in millions)	
Balance, beginning of year	$ —	$ —	$ (20)
Tax Positions related to prior years:			
Reductions	—	—	(2)
Tax Positions related to current year:			
Settlements	—	—	22
Balance, end of year	$ —	$ —	$ —

CERC reported no uncertain tax liability as of December 31, 2015 and expects no significant change to the uncertain tax liability over the next twelve months ending December 31, 2016.

CERC recognizes interest and penalties as a component of income tax expense. CERC recognized $4 million of income tax expense related to interest on tax positions during 2013.

Tax Audits and Settlements. CenterPoint Energy's tax years through 2013 have been audited and settled with the IRS. For 2014 and 2015, CenterPoint Energy is a participant in the IRS's Compliance Assurance Process. CenterPoint Energy has considered the effects of these examinations in its accrual for settled issues and liability for uncertain income tax positions (if any) as of December 31, 2015.

(13) 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, 2015 and 2014 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, 2015, minimum payment obligations for natural gas supply commitments are approximately $478 million in 2016, $457 million in 2017, $405 million in 2018, $217 million in 2019, $90 million in 2020 and $38 million after 2020.

(b) Asset Management Agreements

NGD has asset management agreements (AMAs) associated with its utility distribution service in Arkansas, Louisiana, Mississippi, Oklahoma and Texas. Generally, these 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 agreed to release transportation and storage capacity to other parties to manage 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. The AMAs have varying terms, the longest of which expires in 2019.

(c) Lease Commitments

The following table sets forth information concerning CERC's obligations under non-cancelable long-term operating leases as of December 31, 2015, which primarily consist of rental agreements for building space, data processing equipment, compression equipment and rights-of-way:

		(in millions)
2016	$	5
2017		3
2018		3
2019		3
2020		2
2021 and beyond		7
Total	$	23

Total lease expense for all operating leases was $8 million, $9 million and $20 million during 2015, 2014 and 2013, respectively.

(d) Legal, Environmental and Other Regulatory Matters

Legal Matters

Gas Market Manipulation Cases. CenterPoint Energy, CenterPoint Energy Houston Electric, LLC or their predecessor, Reliant Energy, Incorporated (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, Reliant Resources, Inc. (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 Energy, Inc. (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 CenterPoint Houston, for certain liabilities, including their indemnification obligations regarding the gas market manipulation litigation, nor does it affect the terms of existing guarantee arrangements for certain GenOn gas transportation contracts discussed below.

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 but one such case. CenterPoint Energy Services, Inc. (CES), a subsidiary of CERC Corp., is a defendant in a case now pending in federal court in Nevada alleging a conspiracy to inflate Wisconsin natural gas prices in 2000–2002. In July 2011, the court issued an order dismissing the plaintiffs' claims against other defendants in the case, each of whom had demonstrated Federal Energy Regulatory Commission jurisdictional sales for resale during the relevant period, based on federal preemption, and stayed the remainder of the case pending outcome of the appeals. The plaintiffs appealed this ruling to the U.S. Court of Appeals for the Ninth Circuit, which reversed the trial court's dismissal of the plaintiffs' claims. On April 21, 2015, the U.S. Supreme Court affirmed the Ninth Circuit's ruling and remanded the case to the district court for further proceedings, which are now underway. 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

Manufactured Gas Plant Sites. CERC and its predecessors operated manufactured gas plants (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, 2015, 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 $29 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 potentially responsible parties (PRPs), if any, and the remediation methods used.

In addition to the Minnesota sites, the Environmental Protection Agency 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's predecessors contain or have contained asbestos insulation and other asbestos-containing materials. CERC or its predecessor companies have been named, along with numerous others, as a defendant in lawsuits filed by a number of individuals who claim injury due to exposure to asbestos. Some of the claimants have worked at locations owned by CERC, but most existing claims relate to facilities previously owned by CERC's subsidiaries. CERC anticipates that additional claims like those received may be asserted in the future. Although their ultimate outcome cannot be predicted at this time, CERC intends to continue vigorously contesting claims that it does not consider to have merit and, based on its experience to date, 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 on property where it conducts or has 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, based on its experience to date, 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.

(e) Guarantees

Prior to the distribution of CenterPoint Energy's ownership in RRI to its shareholders, CERC had guaranteed certain contractual obligations of what became RRI's trading subsidiary. When the companies separated, RRI agreed to secure CERC against obligations under the guarantees RRI had been unable to extinguish by the time of separation. Pursuant to such agreement, as amended in December 2007, RRI (now GenOn) agreed to provide to CERC cash or letters of credit as security against CERC's obligations under its remaining guarantees for demand charges under certain gas transportation agreements if and to the extent changes in market conditions expose CERC to a risk of loss on those guarantees based on an annual calculation, with any required collateral to be posted each December. The undiscounted maximum potential payout of the demand charges under these transportation contracts, which will be in effect until 2018, was approximately $27 million as of December 31, 2015. Based on market conditions in the fourth quarter of 2015 at the time the most recent annual calculation was made under the agreement, GenOn was not obligated to post any security. If GenOn should fail to perform the contractual obligations, CERC could have to honor its guarantee and, in such event, any collateral then provided as security may be insufficient to satisfy CERC's obligations.

CERC Corp. has also provided a guarantee of collection of $1.1 billion of Enable's Guaranteed Senior Notes. This guarantee is subordinated to all senior debt of CERC Corp. and is subject to automatic release on May 1, 2016.

The fair value of these guarantees is not material.

(14) Unaudited Quarterly Information

Summarized quarterly financial data is as follows:

	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)

	Year Ended December 31, 2014			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in millions)			
Revenues	$ 2,531	$ 1,183	$ 964	$ 1,689
Operating income (loss)	188	39	(3)	111
Net income	152	48	28	95

(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.

(15) Reportable Business Segments

Because CERC is an indirect, wholly-owned subsidiary of CenterPoint Energy, CERC’s determination of reportable business segments considers the strategic operating units under which CenterPoint Energy 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.

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 investment in Enable. The Other Operations business segment includes unallocated corporate costs and inter-segment eliminations.

Prior to May 1, 2013, CERC also reported an Interstate Pipelines business segment, which included CERC’s interstate natural gas pipeline operations, and a Field Services business segment, which included CERC’s non-rate regulated natural gas gathering, processing and treating operations. The formation of Enable closed on May 1, 2013. Enable now owns substantially all of CERC’s former Interstate Pipelines and Field Services business segments. As a result, effective May 1, 2013, CERC reports equity earnings associated with its interest in Enable under its Midstream Investments segment, and no longer has Interstate Pipelines and Field Services reporting segments prospectively.

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

	Revenues from External Customers	Inter-segment Revenues	Depreciation and Amortization	Operating Income (Loss)	Total Assets	Expenditures for Long-Lived Assets
			(in millions)			
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 (1)	—	—	—	—	2,594	—
Other	—	—	—	(2)	789	—
Reconciling Eliminations	—	(62)	—	—	(744)	—
Consolidated	$ 4,527	$ —	$ 227	$ 313	$ 9,153	$ 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 (1)	—	—	—	—	4,521	—
Other	1	—	—	(4)	1,045	—
Reconciling Eliminations	—	(114)	—	—	(964)	—
Consolidated	$ 6,367	$ —	$ 206	$ 335	$ 11,044	$ 528
As of and for the year ended December 31, 2013:						
Natural Gas Distribution	$ 2,837	$ 26	$ 185	$ 263	$ 4,976	$ 430
Energy Services	2,374	27	5	13	895	3
Interstate Pipelines (2) (3)	133	53	20	72	—	29
Field Services (3)	178	18	20	73	—	16
Midstream Investments (1)	—	—	—	—	4,518	—
Other	—	—	—	(20)	1,139	—
Reconciling Eliminations	—	(124)	—	—	(996)	—
Consolidated	$ 5,522	$ —	$ 230	$ 401	$ 10,532	$ 478

(1) Midstream Investments' equity earnings (losses) are as follows:

	Year Ended December 31,		
	2015	2014	2013
		(in millions)	
Enable (1)	$ (1,633)	$ 303	$ 173
SESH	—	5	8
Total	$ (1,633)	$ 308	$ 181

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

Midstream Investments' total assets are as follows:

	December 31, 2015	December 31, 2014
	(in millions)	
Enable	$ 2,594	$ 4,520
SESH	—	1
Total	$ 2,594	$ 4,521

(2) Interstate Pipelines recorded equity income of $7 million in the year ended December 31, 2013 from its interest in SESH, a jointly-owned pipeline. These amounts are included in Equity in earnings of unconsolidated affiliates under the Other Income (Expense) caption. As discussed above, effective May 1, 2013, CenterPoint Energy reports equity earnings associated with its interest in Enable and equity earnings associated with its interest in SESH under its Midstream Investments segment, and no longer has an Interstate Pipelines reporting segment prospectively.

(3) Results reflected in the year ended December 31, 2013 represent only January 2013 through April 2013.

	Year Ended December 31,		
Revenues by Products and Services:	2015	2014	2013
	(in millions)		
Retail gas sales	$ 3,725	$ 5,049	$ 4,150
Wholesale gas sales	657	1,159	913
Gas transportation and processing	26	38	345
Energy products and services	119	121	114
Total	$ 4,527	$ 6,367	$ 5,522

(16) Subsequent Events

On January 22, 2016, 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, 2015. Accordingly, CERC Corp. expects to receive a cash distribution of approximately $74 million from Enable in the first quarter of 2016 to be made with respect to CERC Corp.'s limited partner interest in Enable for the fourth quarter of 2015.

On January 28, 2016, CenterPoint Energy entered into a purchase agreement with Enable pursuant to which it agreed to purchase in a private placement (Private Placement) an aggregate of 14,520,000 10% Series A Fixed-to-Floating Non-Cumulative Redeemable Perpetual Preferred Units representing limited partner interests in Enable (Series A Preferred Units) for a cash purchase price of $25.00 per Series A Preferred Unit. The Private Placement closed on February 18, 2016. In connection with the Private Placement, Enable redeemed approximately $363 million of notes scheduled to mature in 2017 payable to a wholly-owned subsidiary of CERC Corp. CERC Corp. made a dividend to CenterPoint Energy of $363 million and CenterPoint Energy used the dividend for its investment in the Series A Preferred Units.

On January 29, 2016, CES announced an agreement to acquire the retail commercial and industrial businesses of Continuum Energy Services, a Tulsa and Houston-based company, for $77.5 million plus working capital. The transaction is conditioned upon the receipt of certain third party consents and approvals. CERC expects the transaction to close by the end of the first 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, 2015 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, 2015 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, 2015.

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 4.34, 4.50, 3.34, 3.05 and 3.50 for the years ended December 31, 2015, 2014, 2013, 2012 and 2011, 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, 2015 and 2014 by its principal accounting firm, Deloitte & Touche LLP, are set forth below.

	Year Ended December 31,	
	2015	2014
Audit fees (1)	$ 1,176,480	$ 1,124,640
Audit-related fees (2)	61,073	60,000
Total audit and audit-related fees	1,237,553	1,184,640
Tax fees	—	—
All other fees	—	—
Total fees	$ 1,237,553	$ 1,184,640

(1) For 2015 and 2014, 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 2015 and 2014, 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, 2015

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, III, IV and V.

(a)(3) Exhibits.

See Index of Exhibits beginning on page 96.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the consolidated financial statements of CenterPoint Energy Resources Corp. and subsidiaries (the “Company”, an indirect wholly owned subsidiary of CenterPoint Energy, Inc.) as of December 31, 2015 and 2014, and for each of the three years in the period ended December 31, 2015, and have issued our report thereon dated February 26, 2016; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company listed in the index at Item 15(a)(2). This financial statement schedule is the responsibility of the Company’s management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 26, 2016

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES

(An Indirect, Wholly-Owned Subsidiary of CenterPoint Energy, Inc.)

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
For the Three Years Ended December 31, 2015

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions From Reserves (1)	Balance at End of Period
			(in millions)		
Year Ended December 31, 2015:					
Accumulated provisions:					
Uncollectible accounts receivable	$ 23	$ 19	$ (2)	$ 21	$ 19
Deferred tax asset valuation allowance	2	—	—	—	2
Year Ended December 31, 2014:					
Accumulated provisions:					
Uncollectible accounts receivable	$ 25	$ 20	$ 1	$ 23	$ 23
Deferred tax asset valuation allowance	2	—	—	—	2
Year Ended December 31, 2013:					
Accumulated provisions:					
Uncollectible accounts receivable	$ 23	$ 20	$ —	$ 18	$ 25
Deferred tax asset valuation allowance	2	—	—	—	2

(1) Deductions from reserves represent losses or expenses for which the respective reserves were created. In the case of the uncollectible accounts reserve, such deductions are net of recoveries of amounts previously written off.

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 26th day of February, 2016.

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 26, 2016.

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, 2015

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)	$950,000,000 Credit Agreement dated as of September 9, 2011, among CERC Corp., as Borrower, and the banks named therein	Form 8-K dated September 9, 2011	1-31447	4.3
4(b)(2)	First Amendment to Credit Agreement, dated April 11, 2013, by and among CERC Corp., Citibank, N.A., as administrative agent, and the banks party thereto.	Form 8-K dated April 11, 2013	1-31447	4.2
4(b)(3)	Second Amendment to Credit Agreement, dated September 9, 2013, by and among CERC Corp., Citibank, N.A., as administrative agent, and the banks party thereto.	Form 8-K dated September 9, 2013	1-31447	4.3

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(b)(4)	Third Amendment to Credit Agreement, dated September 9, 2014, by and among CERC Corp., as Borrower, and the banks named therein	Form 8-K dated September 10, 2014	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.	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.	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.	Form 8-K dated May 1, 2013	1-31447	10.4

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
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	1-31447	10.5
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	1-31447	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	1-31447	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)	Third Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP	Form 8-K dated February 18, 2016	1-13265	10.1
+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			

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
+32.1	Section 1350 Certification of Scott M. Prochazka			
+32.2	Section 1350 Certification of William D. Rogers			
99.1	Financial Statements of Enable Midstream Partners, LP as of December 31, 2015 and 2014 and for the years ended December 31, 2015, 2014 and 2013	Part II, Item 8 of Enable Midstream Partners, LP's Form 10-K for the year ended December 31, 2015	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,				
	2015 (1)	2014 (1)	2013 (1)	2012 (1)	2011 (1)
	(in millions)				
Net Income (loss)	$ (912)	$ 323	$ 64	$ 137	$ 316
Equity in (earnings) losses of unconsolidated affiliates, net of distributions	1,927	(2)	(58)	8	8
Income taxes expense (benefit)	(539)	188	371	246	187
Capitalized interest	(2)	(1)	(1)	(2)	—
	474	508	376	389	511
Fixed charges, as defined:					
Interest	137	141	154	179	190
Capitalized interest	2	1	1	2	—
Interest component of rentals charged to operating expense	3	3	6	9	14
Total fixed charges	142	145	161	190	204
Earnings, as defined	$ 616	$ 653	$ 537	$ 579	$ 715
Ratio of earnings to fixed charges	4.34	4.50	3.34	3.05	3.50

(1) Excluded from the computation of fixed charges for the years ended December 31, 2015, 2014, 2013, 2012 and 2011 is interest income of $-0-, $-0-, $3 million, $3 million and $-0-, respectively, 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. 333-193695-01 on Form S-3 of our reports dated February 26, 2016, relating to the consolidated financial statements and financial statement schedule 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, 2015.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 26, 2016

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-193695-01 on Form S-3 of CenterPoint Energy Resources Corp. of our report dated February 17, 2016, relating to the combined and consolidated financial statements of Enable Midstream Partners, LP and subsidiaries, (collectively the "Partnership") (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the preparation of the combined and consolidated financial statements of Enable Midstream Partners, LP from the historical accounting records maintained by CenterPoint Energy, Inc. and its subsidiaries), appearing in this Annual Report on Form 10-K of CenterPoint Energy Resources Corp. for the year ended December 31, 2015.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 26, 2016

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 26, 2016

/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 26, 2016

/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, 2015 (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 26, 2016

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, 2015 (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 26, 2016