CENTERPOINT ENERGY INC
Form 10-K
February 26, 2016

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

Form 10-K
(Mark One)

þ 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

o 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 1-31447

CenterPoint Energy, Inc.	
(Exact name of registrant as specified in its charter)	
Texas	74-0694415
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1111 Louisiana Houston, Texas 77002 (Address and zip code of principal executive offices)	(713) 207-1111 (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
Common Stock, $0.01 par value	New York Stock Exchange Chicago Stock Exchange

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

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

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 þ

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 þ 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 þ 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. o

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

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

The aggregate market value of the voting stock held by non-affiliates of CenterPoint Energy, Inc. (CenterPoint Energy) was $8,146,639,191 as of June 30, 2015, using the definition of beneficial ownership contained in Rule 13d-3 promulgated pursuant to the Securities Exchange Act of 1934 and excluding shares held by directors and executive officers. As of February 12, 2016, CenterPoint Energy had 430,271,749 shares of Common Stock outstanding. Excluded from the number of shares of Common Stock outstanding are 166 shares held by CenterPoint Energy as treasury stock.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement relating to the 2016 Annual Meeting of Shareholders of CenterPoint Energy, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2015, are incorporated by reference in Item 10, Item 11, Item 12, Item 13 and Item 14 of Part III of this Form 10-K.

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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,” “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 Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Future Earnings” and “ — Liquidity and Capital Resources — Other Matters — Other Factors That Could Affect Cash Requirements” in Item 7 of this report, which discussions are incorporated herein by reference.

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

PART I

Item 1. Business

OUR BUSINESS

Overview

We are a public utility holding company. Our operating subsidiaries own and operate electric transmission and distribution facilities and natural gas distribution facilities and own interests in Enable Midstream Partners, LP (Enable) as described below. Our indirect wholly-owned subsidiaries include:

- CenterPoint Energy Houston Electric, LLC (CenterPoint Houston), which engages in the electric transmission and distribution business in the Texas Gulf Coast area that includes the city of Houston; and

- 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.

Our reportable business segments are Electric Transmission & Distribution, 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 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). Additionally, we make available free of charge on our Internet website:

- our Code of Ethics for our Chief Executive Officer and Senior Financial Officers;

- our Ethics and Compliance Code;

- our Corporate Governance Guidelines; and

- the charters of the audit, compensation and governance committees of our Board of Directors.

Any shareholder who so requests may obtain a printed copy of any of these documents from us. Changes in or waivers of our Code of Ethics for our Chief Executive Officer and Senior Financial Officers and waivers of our Ethics and Compliance Code for directors or executive officers will be posted on our Internet website within five business days of such change or waiver and maintained for at least 12 months or reported on Item 5.05 of Form 8-K.

Our website address is www.centerpointenergy.com. Investors should also note that we announce material financial information in SEC filings, press releases and public conference calls. Based on guidance from the SEC, we may use the investor relations section of our website to communicate with our investors. It is possible that the financial and other information posted there could be deemed to be material information. Except to the extent explicitly stated herein, documents and information on our website are not incorporated by reference herein.

Electric Transmission & Distribution

CenterPoint Houston is a transmission and distribution electric utility that operates wholly within the state of Texas. Neither CenterPoint Houston nor any other subsidiary of CenterPoint Energy makes direct retail or wholesale sales of electric energy or owns or operates any electric generating facilities.

Electric Transmission

On behalf of retail electric providers (REPs), CenterPoint Houston delivers electricity from power plants to substations, from one substation to another and to retail electric customers taking power at or above 69 kilovolts (kV) in locations throughout CenterPoint Houston’s certificated service territory. CenterPoint Houston constructs and maintains transmission facilities and provides transmission services under tariffs approved by the Public Utility Commission of Texas (Texas Utility Commission).

Electric Distribution

In the Electric Reliability Council of Texas, Inc. (ERCOT), end users purchase their electricity directly from certificated REPs. CenterPoint Houston delivers electricity for REPs in its certificated service area by carrying lower-voltage power from the substation to the retail electric customer. CenterPoint Houston’s distribution network receives electricity from the transmission grid through power distribution substations and delivers electricity to end users through distribution feeders. CenterPoint Houston’s operations include construction and maintenance of distribution facilities, metering services, outage response services and call center operations. CenterPoint Houston provides distribution services under tariffs approved by the Texas Utility Commission. Texas Utility Commission rules and market protocols govern the commercial operations of distribution companies and other market participants. Rates for these existing services are established pursuant to rate proceedings conducted before municipalities that have original jurisdiction and the Texas Utility Commission.

ERCOT Market Framework

CenterPoint Houston is a member of ERCOT. Within ERCOT, prices for wholesale generation and retail electric sales are unregulated, but services provided by transmission and distribution companies, such as CenterPoint Houston, are regulated by the Texas Utility Commission. ERCOT serves as the regional reliability coordinating council for member electric power systems in most of Texas. ERCOT membership is open to consumer groups, investor and municipally-owned electric utilities, rural electric cooperatives, independent generators, power marketers, river authorities and REPs. The ERCOT market includes most of the State of Texas, other than a portion of the panhandle, portions of the eastern part of the state bordering Arkansas and Louisiana and the area in and around El Paso. The ERCOT market represents approximately 90% of the demand for power in Texas and is one of the nation’s largest power markets. The ERCOT market included available generating capacity of over 77,000 megawatts (MW) as of December 31, 2015. Currently, there are only limited direct current interconnections between the ERCOT market and other power markets in the United States and Mexico.

The ERCOT market operates under the reliability standards set by the North American Electric Reliability Corporation (NERC) and approved by the Federal Energy Regulatory Commission (FERC). Within ERCOT, these reliability standards are administered by the Texas Reliability Entity (TRE). The Texas Utility Commission has primary jurisdiction over the ERCOT market to ensure the adequacy and reliability of electricity supply across the state’s main interconnected power transmission grid. The ERCOT independent system operator (ERCOT ISO) is responsible for operating the bulk electric power supply system in the ERCOT market. Its responsibilities include ensuring that electricity production and delivery are accurately accounted for among the generation resources and wholesale buyers and sellers.

CenterPoint Houston’s electric transmission business, along with those of other owners of transmission facilities in Texas, supports the operation of the ERCOT ISO. The transmission business has planning, design, construction, operation and maintenance responsibility for the portion of the transmission grid and for the load-serving substations it owns, primarily within its certificated area. CenterPoint Houston participates with the ERCOT ISO and other ERCOT utilities to plan, design, obtain regulatory approval for and construct new transmission lines necessary to increase bulk power transfer capability and to remove existing constraints on the ERCOT transmission grid.

Restructuring of the Texas Electric Market

In 1999, the Texas legislature adopted the Texas Electric Choice Plan (Texas electric restructuring law). Pursuant to that legislation, integrated electric utilities operating within ERCOT were required to unbundle their integrated operations into separate retail sales, power generation and transmission and distribution companies. The legislation provided for a transition period to move to the new market structure and provided a mechanism for the formerly integrated electric utilities to recover stranded and certain other costs resulting from the transition to competition. Those costs were recoverable after approval by the Texas Utility Commission either through the issuance of securitization bonds or through the implementation of a competition transition charge as a rider to the utility's tariff. CenterPoint Houston's integrated utility business was restructured in accordance with the Texas electric restructuring law and its generating stations were sold to third parties. Ultimately CenterPoint Houston was authorized to recover a total of approximately $5 billion in stranded costs, other charges and related interest. Most of that amount was recovered through the issuance of transition bonds by special purpose subsidiaries of CenterPoint Houston. The transition bonds are repaid through charges imposed on customers in CenterPoint Houston’s service territory. As of December 31, 2015, approximately $2.3 billion aggregate principal amount of transition bonds were outstanding.

Customers

CenterPoint Houston serves nearly all of the Houston/Galveston metropolitan area. At December 31, 2015, CenterPoint Houston’s customers consisted of approximately 69 REPs, which sell electricity to over 2.3 million metered customers in CenterPoint Houston’s certificated service area, and municipalities, electric cooperatives and other distribution companies located outside CenterPoint Houston’s certificated service area. Each REP is licensed by, and must meet minimum creditworthiness criteria established by, the Texas Utility Commission.

Sales to REPs that are affiliates of NRG Energy, Inc. (NRG) represented approximately 35%, 37% and 38% of CenterPoint Houston’s transmission and distribution revenues in 2015, 2014 and 2013, respectively. Sales to REPs that are affiliates of Energy Future Holdings Corp. (Energy Future Holdings) represented approximately 10% of CenterPoint Houston’s transmission and distribution revenues in each of 2015, 2014 and 2013. CenterPoint Houston’s aggregate billed receivables balance from REPs as of December 31, 2015 was $195 million. Approximately 34% and 11% of this amount was owed by affiliates of NRG and Energy Future Holdings, respectively. CenterPoint Houston does not have long-term contracts with any of its customers. It operates using a continuous billing cycle, with meter readings being conducted and invoices being distributed to REPs each business day.

Advanced Metering System and Distribution Grid Automation (Intelligent Grid)

In May 2012, CenterPoint Houston substantially completed the deployment of an advanced metering system (AMS), having installed approximately 2.2 million smart meters. To recover the cost of the AMS, the Texas Utility Commission approved a monthly surcharge payable by REPs, initially over 12 years and later reduced to six years as a result of U.S. Department of Energy (DOE) grant funds. The surcharge expired in 2015 for residential customers and is set to expire in 2016 to 2017 for non-residential customers. The surcharge amounts and duration are subject to adjustment in future proceedings to reflect actual costs incurred and to address required changes in scope.

CenterPoint Houston is also pursuing deployment of an electric distribution grid automation strategy that involves the implementation of an “Intelligent Grid” (IG) which would provide on-demand data and information about the status of facilities on its system. We expect to include the costs of the deployment in future rate proceedings before the Texas Utility Commission.

In October 2009, the DOE selected CenterPoint Houston for a $200 million grant to help fund its AMS and IG projects. CenterPoint Houston received substantially all of the $200 million of grant funding from the DOE by 2011 and used $150 million of it to accelerate completion of its deployment of advanced meters to 2012. CenterPoint Houston used the other $50 million from the grant for an initial deployment of an IG that covers approximately 12% of its service territory. The DOE-funded portion of the IG project was substantially completed in 2015, and the capital portion of the IG project subject to partial funding by the DOE cost approximately $140 million.

Competition

There are no other electric transmission and distribution utilities in CenterPoint Houston’s service area. In order for another provider of transmission and distribution services to provide such services in CenterPoint Houston’s territory, it would be required to obtain a certificate of convenience and necessity from the Texas Utility Commission and, depending on the location of the facilities, may also be required to obtain franchises from one or more municipalities. We know of no other party intending to enter this business in CenterPoint Houston’s service area at this time. Distributed generation (i.e., power generation located at or near the point of consumption) could result in a reduction of demand for CenterPoint Houston’s electric distribution services but has not been a significant factor to date.

Seasonality

A significant portion of CenterPoint Houston’s revenues is derived from rates that it collects from each REP based on the amount of electricity it delivers on behalf of such REP. Thus, CenterPoint Houston’s revenues and results of operations are subject to seasonality, weather conditions and other changes in electricity usage, with revenues generally being higher during the warmer months.

Properties

All of CenterPoint Houston's properties are located in Texas. Its properties consist primarily of high-voltage electric transmission lines and poles, distribution lines, substations, service centers, service wires and meters. Most of CenterPoint Houston's transmission and distribution lines have been constructed over lands of others pursuant to easements or along public highways and streets under franchise agreements and as permitted by law.

All real and tangible properties of CenterPoint Houston, subject to certain exclusions, are currently subject to:

- the lien of a Mortgage and Deed of Trust (the Mortgage) dated November 1, 1944, as supplemented; and

- the lien of a General Mortgage (the General Mortgage) dated October 10, 2002, as supplemented, which is junior to the lien of the Mortgage.

As of December 31, 2015, CenterPoint Houston had approximately $2.1 billion aggregate principal amount of general mortgage bonds outstanding under the General Mortgage, including (a) approximately $56 million held in trust to secure pollution control bonds that are not reflected on our financial statements because CenterPoint Houston is both the obligor on the bonds and the current owner of the bonds, and (b) approximately $118 million held in trust to secure pollution control bonds for which we are obligated. Additionally, as of December 31, 2015, CenterPoint Houston had approximately $102 million aggregate principal amount of first mortgage bonds outstanding under the Mortgage. CenterPoint Houston may issue additional general mortgage bonds on the basis of retired bonds, 70% of property additions or cash deposited with the trustee. Approximately $4.2 billion of additional first mortgage bonds and general mortgage bonds in the aggregate could be issued on the basis of retired bonds and 70% of property additions as of December 31, 2015. However, CenterPoint Houston has contractually agreed that it will not issue additional first mortgage bonds, subject to certain exceptions.

Electric Lines - Overhead. As of December 31, 2015, CenterPoint Houston owned 28,474 pole miles of overhead distribution lines and 3,723 circuit miles of overhead transmission lines, including 325 circuit miles operated at 69,000 volts, 2,181 circuit miles operated at 138,000 volts and 1,217 circuit miles operated at 345,000 volts.

Electric Lines - Underground. As of December 31, 2015, CenterPoint Houston owned 23,120 circuit miles of underground distribution lines and 26 circuit miles of underground transmission lines, including two circuit miles operated at 69,000 volts and 24 circuit miles operated at 138,000 volts.

Substations. As of December 31, 2015, CenterPoint Houston owned 232 major substation sites having a total installed rated transformer capacity of 58,674 megavolt amperes.

Service Centers. CenterPoint Houston operates 14 regional service centers located on a total of 292 acres of land. These service centers consist of office buildings, warehouses and repair facilities that are used in the business of transmitting and distributing electricity.

Franchises

CenterPoint Houston holds non-exclusive franchises from the incorporated municipalities in its service territory. In exchange for the payment of fees, these franchises give CenterPoint Houston the right to use the streets and public rights-of-way of these municipalities to construct, operate and maintain its transmission and distribution system and to use that system to conduct its electric delivery business and for other purposes that the franchises permit. The terms of the franchises, with various expiration dates, typically range from 20 to 40 years.

Natural Gas Distribution

CERC Corp.'s 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

CERC offers 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 our 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, we entered into a purchase agreement with Enable pursuant to which we 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. We used the proceeds from this redemption for our 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 office buildings and other real estate used in our business operations and other corporate operations that support all of our business operations.

Financial Information About Segments

For financial information about our segments, see Note 17 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.

CenterPoint Houston is not a “public utility” under the Federal Power Act and, therefore, is not generally regulated by the FERC, although certain of its transactions are subject to limited FERC jurisdiction. The FERC has certain responsibilities with respect to ensuring the reliability of electric transmission service, including transmission facilities owned by CenterPoint Houston and other utilities within ERCOT. The FERC has designated the NERC as the Electric Reliability Organization (ERO) to promulgate standards, under FERC oversight, for all owners, operators and users of the bulk power system (Electric Entities). The ERO and the FERC have authority to (a) impose fines and other sanctions on Electric Entities that fail to comply with approved standards and (b) audit compliance with approved standards. The FERC has approved the delegation by the NERC of authority for reliability in ERCOT to the TRE. CenterPoint Houston does not anticipate that the reliability standards proposed by the NERC and approved by the FERC will have a material adverse impact on its operations. To the extent that CenterPoint Houston is required to make additional expenditures to comply with these standards, it is anticipated that CenterPoint Houston will seek to recover those costs through the transmission charges that are imposed on all distribution service providers within ERCOT for electric transmission provided.

As a public utility holding company, under the Public Utility Holding Company Act of 2005, we and our consolidated subsidiaries 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 – Electric Transmission & Distribution

CenterPoint Houston conducts its operations pursuant to a certificate of convenience and necessity issued by the Texas Utility Commission that covers its present service area and facilities. The Texas Utility Commission and certain municipalities have the authority to set the rates and terms of service provided by CenterPoint Houston under cost-of-service rate regulation. CenterPoint Houston holds non-exclusive franchises from certain incorporated municipalities in its service territory. In exchange for payment of fees, these franchises give CenterPoint Houston the right to use the streets and public rights-of-way of these municipalities to construct, operate and maintain its transmission and distribution system and to use that system to conduct its electric delivery business and for other purposes that the franchises permit. The terms of the franchises, with various expiration dates, typically range from 20 to 40 years.

CenterPoint Houston’s distribution rates charged to REPs for residential customers are primarily based on amounts of energy delivered, whereas distribution rates for a majority of commercial and industrial customers are primarily based on peak demand.

All REPs in CenterPoint Houston's service area pay the same rates and other charges for transmission and distribution services. This regulated delivery charge includes the transmission and distribution rate (which includes municipal franchise fees), a distribution recovery mechanism for recovery of incremental distribution-invested capital above that which is already reflected in the base distribution rate, a nuclear decommissioning charge associated with decommissioning the South Texas nuclear generating facility, an energy efficiency cost recovery charge, a surcharge related to the implementation of AMS and charges associated with securitization of regulatory assets, stranded costs and restoration costs relating to Hurricane Ike. Transmission rates charged to distribution companies are based on amounts of energy transmitted under "postage stamp" rates that do not vary with the distance the energy is being transmitted. All distribution companies in ERCOT pay CenterPoint Houston the same rates and other charges for transmission services.

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

State and Local Regulation – Natural Gas Distribution

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 Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters — CERC" 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, electric transmission and distribution systems, 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. CERC's 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 its operations or would have the effect of reducing the consumption of natural gas. Our electric transmission and distribution business, in contrast to some electric utilities, does not generate electricity and thus is not directly exposed to the risk of high capital costs and regulatory uncertainties that face electric utilities that burn fossil fuels to generate electricity. Nevertheless, CenterPoint Houston's revenues could be adversely affected to the extent any resulting regulatory action has the effect of reducing consumption of electricity by ultimate consumers within its service territory. 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 CERC and its 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. On the other hand, warmer temperatures in our electric service territory may increase our revenues from transmission and distribution through increased demand for electricity for cooling. 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 electricity or 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, and back up electrical generators used by our Electric Transmission & 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. 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 EPA and other regulators have investigated MGP sites that were owned or operated by CERC or may have been owned by one of its former affiliates. We do not expect the ultimate outcome of these matters to have a material adverse effect on the financial condition, results of operations or cash flows of either us or CERC.

Asbestos. Some facilities owned by us contain or have contained asbestos insulation and other asbestos-containing materials. We or our subsidiaries 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. In 2004, we sold our generating business, to which most of these claims relate, to a company which is now an affiliate of NRG. Under the terms of the arrangements regarding separation of the generating business from us and our sale of that business, ultimate financial responsibility for uninsured losses from claims relating to the generating business has been assumed by the NRG affiliate, but we have agreed to continue to defend such claims to the extent they are covered by insurance maintained by us, subject to reimbursement of the costs of such defense by the NRG affiliate. 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 7,505 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 Collective Bargaining Groups
Electric Transmission & Distribution	2,665	1,349
Natural Gas Distribution	3,286	1,173
Energy Services	135	—
Other Operations	1,419	110
Total	7,505	2,632

As of December 31, 2015, approximately 35% of our employees were covered by collective bargaining agreements. The collective bargaining agreement with the International Brotherhood of Electrical Workers Local 66 and the two collective bargaining agreements with Professional Employees International Union Local 12, which collectively cover approximately 21% 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.

EXECUTIVE OFFICERS
(as of February 12, 2016)

Name	Age	Title
Milton Carroll	65	Executive Chairman
Scott M. Prochazka	49	President and Chief Executive Officer and Director
William D. Rogers	55	Executive Vice President and Chief Financial Officer
Tracy B. Bridge	57	Executive Vice President and President, Electric Division
Joseph B. McGoldrick	62	Executive Vice President and President, Gas Division
Dana C. O'Brien	48	Senior Vice President, General Counsel and Corporate Secretary
Sue B. Ortenstone	58	Senior Vice President and Chief Human Resources Officer

Milton Carroll has served on the Board of Directors of CenterPoint Energy or its predecessors since 1992. He has served as Executive Chairman of CenterPoint Energy since June 2013 and as Chairman from September 2002 until May 2013. Mr. Carroll has served as a director of Halliburton Company since 2006, Western Gas Holdings, LLC, the general partner of Western Gas Partners, LP, since 2008 and LyondellBasell Industries N.V. since July 2010. He has served as a director of Healthcare Service Corporation since 1998 and as its chairman since 2002. He previously served as a director of LRE GP, LLC, general partner of LRR Energy, L.P., from November 2011 to January 2014.

Scott M. Prochazka has served as a Director and President and Chief Executive Officer (CEO) of CenterPoint Energy since January 1, 2014. He previously served as Executive Vice President and Chief Operating Officer from July 2012 to December 2013; as Senior Vice President and Division President, Electric Operations from May 2011 through July 2012; as Division Senior Vice President, Electric Operations of CenterPoint Houston from February 2009 to May 2011; as Division Senior Vice President Regional Operations of CERC from February 2008 to February 2009; and as Division Vice President, Customer Service Operations from October 2006 to February 2008. He currently serves on the Boards of Directors of Enable GP, LLC, the general partner of Enable Midstream Partners, LP, Gridwise Alliance, Edison Electric Institute, American Gas Association, Greater Houston Partnership and Junior Achievement of South Texas.

William D. Rogers has served as Executive Vice President and Chief Financial Officer of CenterPoint Energy since March 2015. He previously served as Executive Vice President, Finance and Accounting from February 2015 to March 2015. Prior to joining CenterPoint Energy, Mr. Rogers was Vice President and Treasurer of American Water Works Company, Inc., the largest publicly traded U.S. water and wastewater utility company, from October 2010 to January 2015. Mr. Rogers was also the Chief Financial Officer of NV Energy, Inc., an investor-owned utility headquartered in Las Vegas serving approximately 1.5 million electric and gas customers in Nevada and with annual revenues of approximately $3.0 billion, from February 2007 to February 2010. He has previously served as NV Energy's vice president of finance, risk and tax, as well as corporate treasurer. Before joining NV Energy in June 2005, Mr. Rogers was a managing director in capital markets at Merrill Lynch and prior to that in a similar role at JPMorgan Chase in New York. He currently serves on the Board of Directors of Enable GP, LLC, the general partner of Enable Midstream Partners, LP.

Tracy B. Bridge has served as Executive Vice President and President, Electric Division since February 2014. He previously served as Senior Vice President and Division President, Electric Operations from September 2012 to February 2014; as Senior Vice President and Division President, Gas Distribution Operations from May 2011 to September 2012; as Division Senior Vice President - Support Operations from February 2008 to May 2011; and as Division Vice President Regional Operations of CERC from January 2007 to February 2008. He currently serves on the Board of Directors of Rebuilding Together Houston.

Joseph B. McGoldrick has served as Executive Vice President and President, Gas Division since February 2014. He previously served as Senior Vice President and Division President, Gas Operations from September 2012 to February

2014; as Senior Vice President and Division President, Energy Services from May 2011 to September 2012, and as Division President, Gas Operations from February 2007 to May 2011. Mr. McGoldrick is a member of the American Gas Association's Leadership Council.

Dana C. O'Brien has served as Senior Vice President, General Counsel and Corporate Secretary of CenterPoint Energy since May 2014. Before joining CenterPoint Energy, Ms. O'Brien was Chief Legal Officer and Chief Compliance Officer and a member of the executive board at CEVA Logistics, a Dutch-based logistics company, from August 2007 to April 2014. She previously served as the general counsel at EGL, Inc. from October 2005 to July 2007 and Quanta Services, Inc. from January 2001 to October 2005. Ms. O'Brien serves as a director for the Association of Women Attorneys Foundation, a member of the Board of Directors of Ronald McDonald House Houston and as a member of the Board of Directors of Child Advocates, Inc.

Sue B. Ortenstone has served as Senior Vice President and Chief Human Resources Officer of CenterPoint Energy since February 2014. Prior to joining CenterPoint Energy, Ms. Ortenstone was Senior Vice President and Chief Administrative Officer at Copano Energy from July 2012 to May 2013. Before joining Copano, she spent more than 30 years at El Paso Corporation and served most recently as Senior Vice President and then Executive Vice President and Chief Administrative Officer from November 2003 to May 2012. Ms. Ortenstone serves on the Advisory Board for Civil and Environmental Engineering, as well as the Industrial Advisory Board in the College of Engineering at the University of Wisconsin. She also serves on the Board of Trustees for Northwest Assistance Ministries of Houston.

Item 1A. Risk Factors

We are a holding company that conducts all of our business operations through subsidiaries, primarily CenterPoint Houston and CERC. We also own interests in Enable, a publicly traded midstream master limited partnership jointly controlled by CERC Corp. and OGE. 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 the businesses conducted by our subsidiaries and our interests in Enable:

Risk Factors Associated with Our Consolidated Financial Condition

As a holding company with no operations of our own, we will depend on distributions from our subsidiaries and from Enable to meet our payment obligations and to pay dividends on our common stock, and provisions of applicable law or contractual restrictions could limit the amount of those distributions.

We derive all of our operating income from, and hold all of our assets through, our subsidiaries, including our interests in Enable. As a result, we depend on distributions from our subsidiaries, including Enable, in order to meet our payment obligations and to pay dividends on our common stock. In general, our 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.

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 $8.8 billion of outstanding indebtedness on a consolidated basis, which includes $2.7 billion of non-recourse transition and system restoration bonds. As of December 31, 2015, approximately $1.5 billion principal amount of this debt is 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. 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 the markets in which we operate;
- maintenance of acceptable credit ratings;
- market expectations regarding our future earnings and cash flows;
- market perceptions of our 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, in connection with certain indemnification obligations;
- incremental collateral that may be required due to regulation of derivatives; and
- provisions of relevant tax and securities laws.

As of December 31, 2015, CenterPoint Houston had approximately $2.1 billion aggregate principal amount of general mortgage bonds outstanding under the General Mortgage, including (a) approximately $56 million held in trust to secure pollution control bonds that are not reflected on our financial statements because CenterPoint Houston is both the obligor on the bonds and the current owner of the bonds, and (b) approximately $118 million held in trust to secure pollution control bonds for which we are obligated. Additionally, as of December 31, 2015, CenterPoint Houston had approximately $102 million aggregate principal amount of first mortgage bonds outstanding under the Mortgage. CenterPoint Houston may issue additional general mortgage bonds on the basis of retired bonds, 70% of property additions or cash deposited with the trustee. Approximately $4.2 billion of additional first mortgage bonds and general mortgage bonds in the aggregate could be issued on the basis of retired bonds and 70% of property additions as of December 31, 2015. However, CenterPoint Houston has contractually agreed that it will not issue additional first mortgage bonds, subject to certain exceptions.

Our current credit ratings are discussed in “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Other Matters — Impact on Liquidity of a Downgrade in Credit Ratings” in Item 7 of Part II 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 CenterPoint Energy’s 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.

Poor investment performance of the pension plan and factors adversely affecting the calculation of pension liabilities could unfavorably impact our liquidity and results of operations.

We maintain a qualified defined benefit pension plan covering substantially all employees. Our costs of providing this plan are dependent upon a number of factors including the investment returns on plan assets, the level of interest rates used to calculate the funded status of the plan, our contributions to the plan and government regulations with respect to funding requirements and the calculation of plan liabilities. Funding requirements may increase as a result of a decline in the market value of plan assets, a decline in the interest rates used to calculate the present value of future plan obligations or government regulations that increase minimum funding requirements or the pension liability. In addition to affecting our funding requirements, each of these factors could adversely affect our results of operations and financial position.

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.

Risk Factors Affecting Our Electric Transmission & Distribution Business

Rate regulation of CenterPoint Houston’s business may delay or deny CenterPoint Houston’s ability to earn a reasonable return and fully recover its costs.

CenterPoint Houston’s rates are regulated by certain municipalities and the Texas Utility Commission based on an analysis of its invested capital and its expenses in a test year. Thus, the rates that CenterPoint Houston is allowed to charge may not match its costs at any given time, which is referred to as “regulatory lag.” The regulatory process by which rates are determined may not always result in rates that will produce full recovery of CenterPoint Houston’s costs and enable CenterPoint Houston to earn a reasonable return on its invested capital.

Disruptions at power generation facilities owned by third parties could interrupt CenterPoint Houston’s sales of transmission and distribution services.

CenterPoint Houston transmits and distributes to customers of REPs electric power that the REPs obtain from power generation facilities owned by third parties. CenterPoint Houston does not own or operate any power generation facilities. If power generation is disrupted or if power generation capacity is inadequate, CenterPoint Houston’s sales of transmission and distribution services may be diminished or interrupted, and its results of operations, financial condition and cash flows could be adversely affected.

CenterPoint Houston’s revenues and results of operations are seasonal.

A significant portion of CenterPoint Houston’s revenues is derived from rates that it collects from each REP based on the amount of electricity it delivers on behalf of such REP. Thus, CenterPoint Houston’s revenues and results of operations are subject to seasonality, weather conditions and other changes in electricity usage, with revenues generally being higher during the warmer months. Unusually mild weather in the warmer months could diminish our results of operations and harm our financial condition. Conversely, extreme warm weather conditions could increase our results of operations in a manner that would not likely be annually recurring.

The AMS deployed throughout CenterPoint Houston's service territory may experience unexpected problems with respect to the timely receipt of accurate metering data.

CenterPoint Houston has deployed an AMS throughout its service territory. The deployment consisted, among other elements, of replacing existing meters with new electronic meters that record metering data at 15-minute intervals and wirelessly communicate that information to CenterPoint Houston over a bi-directional communications system installed for that purpose. The AMS integrates equipment and computer software from various vendors in order to eliminate the need for physical meter readings to be taken at consumers' premises, such as monthly readings for billing purposes and special readings associated with a customer's change in REPs or the connection or disconnection of electric service. Unanticipated difficulties could be encountered during the operation of the AMS, including failures or inadequacy of equipment or software, difficulties in integrating the various components of the AMS, changes in technology, cyber-security issues and factors outside the control of CenterPoint Houston, which could result in delayed or inaccurate metering data that might lead to delays or inaccuracies in the calculation and imposition of delivery or other charges, which could have a material adverse effect on CenterPoint Houston's results of operations, financial condition and cash flows.

CenterPoint Houston could be subject to higher costs and fines or other sanctions as a result of mandatory reliability standards.

The FERC has jurisdiction with respect to ensuring the reliability of electric transmission service, including transmission facilities owned by CenterPoint Houston and other utilities within ERCOT. The FERC has designated the NERC as the ERO to promulgate standards, under FERC oversight, for all owners, operators and users of the bulk power system. The FERC has approved the delegation by the NERC of authority for reliability in ERCOT to the TRE, a functionally independent division of ERCOT. Compliance with the mandatory reliability standards may subject CenterPoint Houston to higher operating costs and may result in increased capital expenditures. In addition, if CenterPoint Houston were to be found to be in noncompliance with applicable mandatory reliability standards, it could be subject to sanctions, including substantial monetary penalties.

A substantial portion of CenterPoint Houston's receivables is concentrated in a small number of REPs, and any delay or default in payment could adversely affect CenterPoint Houston's cash flows, financial condition and results of operations.

CenterPoint Houston's receivables from the distribution of electricity are collected from REPs that supply the electricity CenterPoint Houston distributes to their customers. As of December 31, 2015, CenterPoint Houston did business with approximately 69 REPs. Adverse economic conditions, structural problems in the market served by ERCOT or financial difficulties of one or more REPs could impair the ability of these REPs to pay for CenterPoint Houston's services or could cause them to delay such payments. CenterPoint Houston depends on these REPs to remit payments on a timely basis. Applicable regulatory provisions require that customers be shifted to another REP or a provider of last resort if a REP cannot make timely payments. Applicable Texas Utility Commission regulations significantly limit the extent to which CenterPoint Houston can apply normal commercial terms or otherwise seek credit protection from firms desiring to provide retail electric service in its service territory, and CenterPoint Houston thus remains at risk for payments related to services provided prior to the shift to another REP or the provider of last resort. The Texas Utility Commission revised its regulations in 2009 to (i) increase the financial qualifications required of REPs that began selling power after January 1, 2009, and (ii) authorize utilities to defer bad debts resulting from defaults by REPs for recovery in a future rate case. A significant portion of CenterPoint Houston's billed receivables from REPs are from affiliates of NRG and Energy Future Holdings Corp. (Energy Future Holdings). CenterPoint Houston's aggregate billed receivables balance from REPs as of December 31, 2015 was $195 million. Approximately 34% and 11% of this amount was owed by affiliates of NRG and Energy Future Holdings, respectively. In April 2014, Energy Future Holdings publicly disclosed that it and the substantial majority of its direct and indirect subsidiaries, excluding Oncor Electric Delivery Company LLC and its subsidiaries, filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware. Any delay or default in payment by REPs could adversely affect CenterPoint Houston's cash flows, financial condition and results of operations. If a REP were unable to meet its obligations, it could consider, among various options, restructuring under the bankruptcy laws, in which event such REP might seek to avoid honoring its obligations, and claims might be made by creditors involving payments CenterPoint Houston had received from such REP.

Risk Factors Affecting Our Natural Gas Distribution and Energy Services Businesses

Rate regulation of CERC’s business may delay or deny CERC’s ability to earn a reasonable return and fully recover its costs.

CERC’s rates for NGD are regulated by certain municipalities and state commissions based on an analysis of its invested capital and its expenses in a test year. Thus, the rates that CERC is allowed to charge may not match its 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 CERC’s costs and enable CERC to earn a reasonable return on its invested capital.

CERC’s 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 CERC’s suppliers and customers to meet their obligations or otherwise adversely affect CERC’s liquidity and results of operations and financial condition.

CERC is 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 CERC’s ability to collect balances due from its customers and, for NGD, could create the potential for uncollectible accounts expense to exceed the recoverable levels built into CERC’s tariff rates. In addition, a sustained period of high natural gas prices could (i) decrease demand for natural gas in the areas in which

CERC operates, thereby resulting in decreased sales and revenues and (ii) increase the risk that CERC's suppliers or customers fail or are unable to meet their obligations. An increase in natural gas prices would also increase CERC's 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 CERC must provide under its hedging arrangements.

A decline in CERC's credit rating could result in CERC's having to provide collateral under its shipping or hedging arrangements or in order to purchase natural gas.

If CERC's credit rating were to decline, it might be required to post cash collateral under its 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 CERC was experiencing significant working capital requirements or otherwise lacked liquidity, CERC's results of operations, financial condition and cash flows could be adversely affected.

CERC's revenues and results of operations are seasonal.

A substantial portion of CERC's revenues is derived from natural gas sales. Thus, CERC's 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 CERC provides 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 CERC's ability to operate.

Proposals have been put forth in some of the states in which CERC does 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 CERC's ability to conduct its utility operations, to finance its 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 CERC and us to comply with competing regulatory requirements.

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

CERC competes 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 CERC 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 CERC's 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 CERC as a result of competition may have an adverse impact on CERC's 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. We also hold $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, electric transmission and distribution systems, 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.

In common with other companies in its line of business that serve coastal regions, CenterPoint Houston does not have insurance covering its transmission and distribution system, other than substations, because CenterPoint Houston believes it to be cost prohibitive. In the future, CenterPoint Houston may not be able to recover the costs incurred in restoring its transmission and distribution properties following hurricanes or other disasters through issuance of storm restoration bonds or a change in its regulated rates or otherwise, or any such recovery may not be timely granted. Therefore, CenterPoint Houston may not be able to restore any loss of, or damage to, any of its transmission and distribution properties without negative impact on its 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, CenterPoint Houston and CERC could incur liabilities associated with businesses and assets that we have transferred to others.

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

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

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

In connection with the organization and capitalization of RRI (now GenOn), 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, us and our subsidiaries, including CenterPoint Houston and CERC, 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, CenterPoint Houston or CERC could be responsible for satisfying the liability.

Prior to the distribution of our ownership in RRI to our 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.

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 us 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, CenterPoint Houston or CERC could incur liability if claims in one or more of these lawsuits were successfully asserted against us, CenterPoint Houston or CERC and indemnification from GenOn were determined to be unavailable or if GenOn were unable to satisfy indemnification obligations owed with respect to those claims.

In connection with the organization and capitalization of Texas Genco (now an affiliate of NRG), Reliant Energy and Texas Genco entered into a separation agreement in which Texas Genco assumed liabilities associated with the electric generation assets Reliant Energy transferred to it. Texas Genco also agreed to indemnify, and cause the applicable transferee subsidiaries to indemnify, us and our subsidiaries, including CenterPoint Houston, with respect to liabilities associated with the transferred assets and businesses. In many cases the liabilities assumed were obligations of CenterPoint Houston, and CenterPoint Houston was not released by third parties from these liabilities. The indemnity provisions were intended generally to place sole financial responsibility on Texas Genco and its subsidiaries for all liabilities associated with the current and historical businesses and operations of Texas Genco, regardless of the time those liabilities arose. If Texas Genco were unable to satisfy a liability that had been so assumed or indemnified against, and provided we or Reliant Energy had not been released from the liability in connection with the transfer, CenterPoint Houston could be responsible for satisfying the liability.

In connection with our sale of Texas Genco, the separation agreement was amended to provide that Texas Genco would no longer be liable for, and we would assume and agree to indemnify Texas Genco against, liabilities that Texas Genco originally assumed in connection with its organization to the extent, and only to the extent, that such liabilities are covered by certain insurance policies held by us.

We or our subsidiaries 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 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. Under the terms of the arrangements regarding separation of the generating business from us and our sale of that business to an affiliate of NRG, ultimate financial responsibility for uninsured losses from claims relating to the generating business has been assumed by the NRG affiliate, but we have agreed to continue to defend such claims to the extent they are covered by insurance maintained by us, subject to reimbursement of the costs of such defense by the NRG affiliate.

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 operation of our electric transmission and distribution system is dependent on not only physical interconnection of our facilities, but also on communications among the various components of our system. As we deploy smart meters and the intelligent grid, reliance on communication between and among those components increases. Similarly, 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, electrical distribution and transmission facilities and 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, shareholders and employees. Our customers, shareholders 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, shareholder, employee or CenterPoint Energy 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, CERC’s 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. Our electric transmission and distribution business, in contrast to some electric utilities, does not generate electricity and thus is not directly exposed to the risk of high capital costs and regulatory uncertainties that face electric utilities that burn fossil fuels to generate electricity. Nevertheless, CenterPoint Houston’s revenues could be adversely affected to the extent any resulting regulatory action has the effect of reducing consumption of electricity by ultimate consumers within its service territory. 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 electricity or 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.

CenterPoint Energy has 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 seven separate bargaining units in CenterPoint Energy, each with a unique collective bargaining agreement. The collective bargaining agreement with the International Brotherhood of Electrical Workers Local 66 and the 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.

Our business could be negatively affected as a result of the actions of activist shareholders.

Publicly traded companies have increasingly become subject to campaigns by activist investors advocating corporate actions such as financial restructuring, increased borrowing, special dividends, stock repurchases or even sales of assets or the entire company. It is possible that activist shareholders may attempt to effect such changes or acquire control over us. Responding to proxy contests and other actions by activist shareholders can be costly and time-consuming, disrupt our operations and divert the attention of our board of directors and senior management from the pursuit of business strategies, which could adversely affect our results of operations and financial condition. Additionally, perceived uncertainties as to our future direction as a result of shareholder activism or changes to the composition of the board of directors may lead to the perception of a change in the direction of the business, instability or lack of continuity. This may be exploited by our competitors, cause concern to our current or potential customers, and make it more difficult to attract and retain qualified personnel.

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 Note14 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 our 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 lease or own our principal properties in fee, including our corporate office space and various real property. Most of our electric lines and gas mains are located, pursuant to easements and other rights, on public roads or on land owned by others.

Electric Transmission & Distribution

For information regarding the properties of our Electric Transmission & Distribution business segment, please read "Business — Our Business — Electric Transmission & Distribution — Properties" in Item 1 of this report, which information i incorporated herein by reference.

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.

Other Operations

For information regarding the properties of our Other Operations business segment, please read "Business — Our Business — Other Operations" 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 Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of this report and Note 14(d) to our consolidated financial statements, which information is incorporated herein by reference.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

As of February 12, 2016, our common stock was held by approximately 34,130 shareholders of record. Our common stock is listed on the New York and Chicago Stock Exchanges and is traded under the symbol "CNP."

The following table sets forth the high and low closing prices of the common stock of CenterPoint Energy on the New York Stock Exchange composite tape during the periods indicated, as reported by Bloomberg, and the cash dividends declared in these periods.

	Market Price		Dividend Declared
	High	Low	Per Share
2015			
First Quarter			$0.2475
January 2	$23.63		
March 31		$20.41	
Second Quarter			$0.2475
April 15	$21.31		
June 30		$19.03	
Third Quarter			$0.2475
August 14	$19.92		
September 29		$17.53	
Fourth Quarter			$0.2475
October 22	$19.13		
December 10		$16.14	
2014			
First Quarter			$0.2375
January 3		$22.81	
February 21	$24.48		
Second Quarter			$0.2375
April 7		$23.39	
June 30	$25.54		
Third Quarter			$0.2375
July 1	$25.38		
August 6		$23.56	
Fourth Quarter			$0.2375
November 10	$25.38		
December 15		$21.54	

The closing market price of our common stock on December 31, 2015 was $18.36 per share.

The amount of future cash dividends will be subject to determination based upon our results of operations and financial condition, our future business prospects, any applicable contractual restrictions and other factors that our board of directors considers relevant and will be declared at the discretion of the board of directors.

On January 20, 2016, our board of directors declared a regular quarterly cash dividend of $0.2575 per share, payable on March 10, 2016 to shareholders of record on February 16, 2016.

Repurchases of Equity Securities

During the quarter ended December 31, 2015, none of our equity securities registered pursuant to Section 12 of the Securities Exchange Act of 1934 were purchased by or on behalf of us or any of our "affiliated purchasers," as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934.

Item 6. Selected Financial Data

The following table presents selected financial data with respect to our consolidated financial condition and consolidated results of operations and should be read in conjunction with our consolidated financial statements and the related notes in Item 8 of this report.

	Year Ended December 31,				
	2015	2014	2013	2012	2011 (4)
	(in millions, except per share amounts)				
Revenues	$7,386	$9,226	$8,106	$7,452	$8,450
Equity in Earnings (Losses) of Unconsolidated Affiliates	(1,633) (1)	308 (2)	188 (3)	31	30
Income (Loss) before Extraordinary Item	(692)	611	311	417	770
Extraordinary Item, net of tax	—	—	—	—	587
Net income (loss)	$(692)	$611	$311	$417	$1,357
Basic earnings (loss) per common share:					
Income (Loss) before Extraordinary Item	$(1.61)	$1.42	$0.73	$0.98	$1.81
Extraordinary Item, net of tax	—	—	—	—	1.38
Basic earnings (loss) per common share	$(1.61)	$1.42	$0.73	$0.98	$3.19
Diluted earnings (loss) per common share:					
Income (Loss) before Extraordinary Item	$(1.61)	$1.42	$0.72	$0.97	$1.80
Extraordinary Item, net of tax	—	—	—	—	1.37
Diluted earnings (loss) per common share	$(1.61)	$1.42	$0.72	$0.97	$3.17
Cash dividends declared per common share	$0.99	$0.95	$0.83	$0.81	$0.79
Dividend payout ratio	n/a	67%	114%	83%	44% (5)
Return on average common equity	(17)%	14%	7%	10%	21% (5)
Ratio of earnings to fixed charges	2.67	2.79	2.42	2.29	2.96 (5)
At year-end:					
Book value per common share	$8.05	$10.58	$10.09	$10.09	$9.91
Market price per common share	18.36	23.43	23.18	19.25	20.09
Market price as a percent of book value	228%	221%	230%	191%	203%
Total assets	$21,334	$23,200	$21,870	$22,871	$21,703
Short-term borrowings	40	53	43	38	62
Transition and system restoration bonds, including current maturities	2,674	3,046	3,400	3,847	2,522
Other long-term debt, including current maturities	6,100	5,758	4,914	5,910	6,603
Capitalization:					
Common stock equity	28%	34%	34%	31%	32%
Long-term debt, including current maturities	72%	66%	66%	69%	68%
Capitalization, excluding transition and system restoration bonds:					
Common stock equity	36%	44%	47%	42%	39%

Long-term debt, excluding transition and system restoration bonds, and including current maturities	64 %	56 %	53 %	58 %	61 %
Capital expenditures	$1,575	$1,402	$1,272	$1,188	$1,191

(1) As of December 31, 2015, we owned approximately 55.4% of the limited partner interests in Enable Midstream Partners, LP (Enable), an unconsolidated subsidiary that we account for on an equity basis. This amount includes $1,846 million of non-cash impairment charges related to Enable.

(2) As of December 31, 2014, we owned approximately 55.4% of the limited partner interests in Enable and 0.1% of Southeast Supply Header (SESH), each an unconsolidated subsidiary, that we accounted for on an equity basis.

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(3) Following the formation of Enable on May 1, 2013, Enable owned substantially all of our former Interstate Pipelines and Field Services business segments, except for our retained 25.05% interest in SESH. As of December 31, 2013, we owned approximately 58.3% of the limited partner interests in Enable.

(4) 2011 Income before Extraordinary Item includes a $224 million after-tax ($0.53 and $0.52 per basic and diluted share, respectively) return on true-up balance related to a portion of interest on the appealed true-up amount.

(5) Calculated using Income before Extraordinary Item.

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

The following discussion and analysis should be read in combination with our consolidated financial statements included in Item 8 herein.

OVERVIEW

Background

We are a public utility holding company. Our operating subsidiaries own and operate electric transmission and distribution facilities and natural gas distribution facilities and own interests in Enable Midstream Partners, LP (Enable) as described below. Our indirect wholly-owned subsidiaries include:

- CenterPoint Energy Houston Electric, LLC (CenterPoint Houston), which engages in the electric transmission and distribution business in the Texas Gulf Coast area that includes the city of Houston; and

- CenterPoint Energy Resources Corp. (CERC Corp. and, together with its subsidiaries, CERC), which owns and operates 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, which owns, operates and develops natural gas and crude oil infrastructure assets.

Business Segments

In this Management's Discussion and Analysis, we discuss our results from continuing operations on a consolidated basis and individually for each of our business segments. We also discuss our liquidity, capital resources and critical accounting policies. We are first and foremost an energy delivery company and it is our intention to remain focused on these segments of the energy business. The results of our business operations are significantly impacted by weather, customer growth, economic conditions, cost management, competition, rate proceedings before regulatory agencies and other actions of the various regulatory agencies to whose jurisdiction we are subject. Our electric transmission and distribution services are subject to rate regulation and are reported in the Electric Transmission & Distribution business segment, as are impacts of generation-related stranded costs and other true-up balances recoverable by the regulated electric utility. Our natural gas distribution services are also 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:

Electric Transmission & Distribution

Our electric transmission and distribution operations provide electric transmission and distribution services to retail electric providers (REPs) serving over 2.3 million metered customers in a 5,000-square-mile area of the Texas Gulf Coast that has a population of approximately six million people and includes the city of Houston.

On behalf of REPs, CenterPoint Houston delivers electricity from power plants to substations, from one substation to another and to retail electric customers in locations throughout CenterPoint Houston’s certificated service territory. The Electric Reliability Council of Texas, Inc. (ERCOT) serves as the regional reliability coordinating council for member electric power systems in Texas. ERCOT membership is open to consumer groups, investor and municipally-owned electric utilities, rural electric cooperatives, independent generators, power marketers, river authorities and REPs. The ERCOT market represents approximately 90% of the demand for power in Texas and is one of the nation's largest power markets. Transmission and distribution services are provided under tariffs approved by the Public Utility Commission of Texas (Texas Utility Commission).

Natural Gas Distribution

CERC owns and operates 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

CERC's 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 office buildings and other real estate used in our business operations and other corporate operations which support all of our business operations.

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 and the transmission and delivery of electricity by our subsidiaries. We do not own or operate electric generating facilities or make retail sales to end-use electric customers. 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 and cooling 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 Electric Transmission & Distribution and Natural Gas Distribution business segments 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 electric and 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.

We expect to make contributions to our pension plans aggregating approximately $8 million in 2016 but may need to make larger contributions in subsequent years. Consistent with the regulatory treatment of such costs, we can defer the amount of pension expense that differs from the level of pension expense included in our base rates for our Electric Transmission & Distribution business segment and 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 9 to our consolidated financial statements.

Brazos Valley Connection Project. In April 2015, CenterPoint Houston filed a Certificate of Convenience and Necessity (CCN) application with the Texas Utility Commission seeking approval to construct the Brazos Valley Connection (CenterPoint Houston's portion of the Houston region transmission project). CenterPoint Houston proposed 32 alternative routes for the project in the application, including one route (the Recommended Route) that CenterPoint Houston identified in the application as best meeting the routing criteria used by the Texas Utility Commission in the route selection portion of CCN proceedings. The hearing on CenterPoint Houston's CCN application was divided into two phases, a route-selection phase and a need phase. The route selection hearing was held on August 17 and 18, 2015. The hearing on the need for the line was held on September 2 and 3, 2015. On January 15, 2016, the Texas Utility Commission issued an order finding that the evidence presented by CenterPoint Houston, ERCOT, and others established the need for the project and approving a CCN for CenterPoint Houston to construct the Brazos

Valley Connection using a modified version of the Recommended Route. A request for rehearing was filed with respect to the Texas Utility Commission's route selection decision. That request for rehearing will be automatically deemed denied by operation of law on March 10, 2016, unless the Texas Utility Commission acts on the request before that date. The Texas Utility Commission's order provided an estimated range of approximately $270–$310 million for the capital costs for the Brazos Valley Connection. The actual cost will depend on factors including land acquisition costs, material and construction costs and landowner elections permitted under the Texas Utility Commission's order. CenterPoint Houston expects to complete construction of the Brazos Valley Connection by mid-2018.

Transmission Cost of Service (TCOS). On June 26, 2015, CenterPoint Houston filed an application with the Texas Utility Commission for an interim update of its TCOS seeking an increase in annual transmission revenues based on an incremental increase of $87.6 million in total rate base. The Texas Utility Commission approved CenterPoint Houston's application in the third quarter of 2015, and rates became effective August 17, 2015, resulting in an increase of $13.7 million in annual transmission revenues.

On October 1, 2015, CenterPoint Houston filed an application with the Texas Utility Commission for an interim update of its TCOS seeking an increase in annual transmission revenues based on an incremental increase of $107.6 million in total rate base. The Texas Utility Commission approved CenterPoint Houston's application in the fourth quarter of 2015, and rates became effective November 23, 2015, resulting in an increase of $16.8 million in annual transmission revenue.

Distribution Cost Recovery Factor (DCRF). On April 6, 2015, CenterPoint Houston filed an application with the Texas Utility Commission for a DCRF interim rate adjustment to account for changes in certain distribution-invested capital since its 2010 rate case. The application requested (i) an increase in annual distribution revenue of $16.7 million based on an increase in rate base from January 1, 2010 through December 31, 2014 of $417 million; and (ii) that rates become effective September 1, 2015.

On June 19, 2015, an unopposed settlement agreement was filed providing for an increase in annual distribution revenue of $13.0 million, subject to final Texas Utility Commission approval. The Texas Utility Commission approved the settlement agreement on July 30, 2015. Rates became effective September 1, 2015.

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.

Tender Offer for AOL Inc. Common Stock. On May 26, 2015, Verizon Communications, Inc. (Verizon) initiated a tender offer to purchase all outstanding shares of AOL Inc. common stock (AOL Common) for $50 per share, in which we tendered all of our shares of AOL Common for $32 million. Verizon acquired the remaining eligible shares through a merger, which closed on June 23, 2015. In accordance with the terms of the Zero-Premium Exchangeable Subordinated Notes due 2029 (ZENS), we remitted $32 million to ZENS holders in July 2015, which reduced contingent principal. As a result, we recorded a reduction in the indexed debt securities derivative liability of $18 million, a reduction in the indexed debt balance of $7 million and a loss of $7 million. As of December 31, 2015, the reference shares for each ZENS note consisted of 0.5 share of Time Warner Inc. common stock (TW Common), 0.125505 share of Time Warner Cable Inc. (TWC) common stock (TWC Common) and 0.0625 share of Time Inc. common stock (Time Common).

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.

Debt Repayments. In June 2015, we repaid our $200 million 6.85% Senior Notes using proceeds from our commercial paper program. In October 2015, we repaid our $69 million 4.9% pollution control bonds using proceeds from our commercial paper program.

Retirement of Bonds. In November 2015, we retired $740 million of tax-exempt municipal bonds that had been held for remarketing.

Private Placement. On January 28, 2016, we entered into a purchase agreement with Enable pursuant to which we 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. We used the proceeds from this redemption for our investment in the Series A Preferred Units.

Continuum Acquisition. On January 29, 2016, CenterPoint Energy Services (CES), our indirect, 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 our 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;

- timely and appropriate regulatory actions allowing securitization or other recovery of costs associated with any future hurricanes or natural disasters;
- 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. (NRG), 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 ability of REPs, including REP affiliates of NRG and Energy Future Holdings Corp., to satisfy their obligations to us and our subsidiaries;

- changes in technology, particularly with respect to efficient battery storage or the emergence or growth of new, developing or alternative sources of generation;
- the timing and outcome of any audits, disputes and other proceedings related to taxes;
- the effective tax rates;
- 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

All dollar amounts in the tables that follow are in millions, except for per share amounts.

	Year Ended December 31,		
	2015	2014	2013
Revenues	$7,386	$9,226	$8,106
Expenses	6,453	8,291	7,096
Operating Income	933	935	1,010
Gain (Loss) on Marketable Securities	(93)	163	236
Gain (Loss) on Indexed Debt Securities	74	(86)	(193)
Interest and Other Finance Charges	(352)	(353)	(351)
Interest on Transition and System Restoration Bonds	(105)	(118)	(133)
Equity in Earnings (Losses) of Unconsolidated Affiliates	(1,633)	308	188
Other Income, net	46	36	24
Income (Loss) Before Income Taxes	(1,130)	885	781
Income Tax Expense (Benefit)	(438)	274	470
Net Income (Loss)	$(692)	$611	$311
Basic Earnings (Loss) Per Share	$(1.61)	$1.42	$0.73
Diluted Earnings (Loss) Per Share	$(1.61)	$1.42	$0.72

2015 Compared to 2014

Net Income. We reported a net loss of $692 million ($(1.61) per diluted share) for 2015 compared to net income of $611 million ($1.42 per diluted share) for the same period in 2014.

The decrease in net income of $1,303 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 9 to our consolidated financial statements; and
- a $256 million increase in the loss on our marketable securities.

These decreases were partially offset by:

- a $712 million decrease in income tax expense;

- a $160 million increase in the gain on our indexed debt securities;
- a $13 million decrease in interest expense related to our transition and system restoration bonds; and
- an $10 million increase in other income.

Income Tax Expense. We reported an effective tax rate of 38.8% and 31.0% for the years ended December 31, 2015 and 2014, respectively. The higher effective tax rate of 38.8% is primarily due to lower earnings from the impairment of our investment in Enable. The impairment loss reduced the deferred tax liability on our investment in Enable. The effective tax rate of 31.0% for 2014 is primarily due to a $29 million tax benefit recognized upon completion of a tax basis balance sheet review and a $13 million reversal of previously accrued taxes as a result of final positions taken in the 2013 tax returns. We determined the impact of the $29 million adjustment was not material to any prior period or the year ended December 31, 2014.

2014 Compared to 2013

Net Income. We reported net income of $611 million ($1.42 per diluted share) for 2014 compared to $311 million ($0.72 per diluted share) for the same period in 2013.

The increase in net income of $300 million was due to the following key factors:

- a $196 million decrease in income tax expense discussed below;
- a $120 million increase in equity earnings of unconsolidated affiliates;
- a $107 million decrease in the loss on our indexed debt securities;
- a $13 million decrease in interest expense; and
- a $12 million increase in other income.

These increases were partially offset by:

- a $75 million decrease in operating income (discussed below by segment); and
- a $73 million decrease in the gain on our marketable securities.

Income Tax Expense. We reported an effective tax rate of 31.0% and 60.2% for the years ended December 31, 2014 and 2013, respectively. The effective tax rate of 31.0% for 2014 is primarily due to a $29 million tax benefit recognized upon completion of a tax basis balance sheet review and a $13 million reversal of previously accrued taxes as a result of final positions taken in the 2013 tax returns. We determined the impact of the $29 million adjustment was not material to any prior period or the year ended December 31, 2014. The effective tax rate of 60.2% for 2013 is primarily attributable to a net $196 million charge to deferred tax expense due to the formation of Enable. For more information, see Note 13 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)		
Electric Transmission & Distribution	$607	$595	$607
Natural Gas Distribution	273	287	263
Energy Services	42	52	13
Interstate Pipelines	—	—	72
Field Services	—	—	73
Other Operations	11	1	(18)
Total Consolidated Operating Income	$933	$935	$1,010

Electric Transmission & Distribution

The following tables provide summary data of our Electric Transmission & Distribution business segment for 2015, 2014 and 2013:

	Year Ended December 31,		
	2015	2014	2013
Revenues:	(in millions, except throughput and customer data)		
Electric transmission and distribution utility	$2,364	$2,279	$2,063
Transition and system restoration bond companies	481	566	507
Total revenues	2,845	2,845	2,570
Expenses:			
Operation and maintenance, excluding transition and system restoration bond companies	1,300	1,251	1,045
Depreciation and amortization, excluding transition and system restoration bond companies	340	327	319
Taxes other than income taxes	222	224	225
Transition and system restoration bond companies	376	448	374
Total expenses	2,238	2,250	1,963
Operating Income	$607	$595	$607
Operating Income:			
Electric transmission and distribution operations	$502	$477	$474
Transition and system restoration bond companies (1)	105	118	133
Total segment operating income	$607	$595	$607
Throughput (in gigawatt-hours (GWh)):			
Residential	28,995	27,498	27,485
Total	84,191	81,839	79,985
Number of metered customers at end of period:			
Residential	2,079,899	2,033,027	1,982,699
Total	2,348,517	2,299,247	2,244,289

(1) Represents the amount necessary to pay interest on the transition and system restoration bonds.

2015 Compared to 2014. Our Electric Transmission & Distribution business segment reported operating income of $607 million for 2015, consisting of $502 million from our regulated electric transmission and distribution utility operations (TDU) and $105 million related to transition and system restoration bond companies (Bond Companies). For 2014, operating income totaled $595 million, consisting of $477 million from the TDU and $118 million related to Bond Companies.

TDU operating income increased $25 million due to the following key factors:

- higher transmission-related revenues of $81 million, which were partially offset by increased transmission costs billed by transmission providers of $47 million;

- customer growth of $25 million from the addition of nearly 50,000 new customers;

- higher usage of $17 million, primarily due to a return to normal weather; and

- rate relief associated with distribution capital investments of $5 million.

These increases to operating income were partially offset by the following:

•lower equity return of $20 million, primarily related to true-up proceeds;

- lower revenues from energy efficiency bonuses of $15 million, including a one-time energy efficiency remand bonus in 2014 of $8 million;
- higher depreciation of $13 million; and
- lower right-of-way revenues of $7 million.

2014 Compared to 2013. Our Electric Transmission & Distribution business segment reported operating income of $595 million for 2014, consisting of $477 million from the TDU and $118 million related to Bond Companies. For 2013, operating income totaled $607 million, consisting of $474 million from the TDU and $133 million related to Bond Companies.

TDU operating income increased $3 million due to the following key factors:

- customer growth of $33 million from the addition of almost 55,000 new customers;
- higher equity return of $23 million, primarily related to true-up proceeds; and
- higher energy efficiency performance bonus of $15 million.

These increases to operating income were partially offset by the following:

- increased labor and support services costs of $21 million;
- increased contracts and services of $19 million;
- lower right-of-way revenues of $8 million;
- increased depreciation of $8 million;
- an adjustment to our claims liability reserve of $6 million;
- decreased usage of $5 million, primarily due to milder weather; and
- increased transmission costs billed by transmission providers of $168 million, which were largely offset by increased transmission-related revenues of $164 million.

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

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.

Other Operations

The following table provides summary data for our Other Operations business segment for 2015, 2014 and 2013:

	Year Ended December 31,		
	2015	2014	2013
	(in millions)		
Revenues	$14	$15	$14
Expenses	3	14	32
Operating Income (Loss)	$11	$1	$(18)

2015 Compared to 2014. Our Other Operations business segment reported operating income of $11 million for 2015 compared to $1 million for 2014. The increase in operating income of $10 million is primarily related to decreased administrative and benefits costs ($8 million), decreased depreciation and amortization ($1 million) and decreased property taxes ($1 million).

2014 Compared to 2013. Our Other Operations business segment reported operating income of $1 million for 2014 compared to an operating loss of $18 million for 2013. The increase in operating income of $19 million is primarily related to the costs associated with the formation of Enable in 2013 ($13 million) and decreased benefits costs ($8 million), which were partially offset by higher property taxes ($2 million).

LIQUIDITY AND CAPITAL RESOURCES

Historical Cash Flows

The net cash provided by (used in) operating, investing and financing activities for 2015, 2014 and 2013 is as follows:

	Year Ended December 31,		
	2015	2014	2013
	(in millions)		
Cash provided by (used in):			
Operating activities	$1,865	$1,397	$1,613
Investing activities	(1,387)	(1,384)	(1,300)
Financing activities	(512)	77	(751)

Cash Provided by Operating Activities

Net cash provided by operating activities increased $468 million in 2015 compared to 2014 primarily due to decreased net tax payments ($237 million), increased cash related to a decrease in gas storage inventory ($113 million), increased cash provided by net accounts receivable/payable ($85 million), increased cash provided by fuel cost recovery ($84 million), decreased net margin deposits ($75 million), increased cash provided by net regulatory assets and liabilities ($41 million) and increased cash from non-trading derivatives ($27 million), which were partially offset by decreased distributions from equity method investments ($159 million).

Net cash provided by operating activities decreased $216 million in 2014 compared to 2013 primarily due to increased net tax payments ($157 million), decreased cash provided by fuel cost recovery ($149 million), increased net margin deposits ($95 million), decreased cash related to gas storage inventory ($69 million), decreased cash from non-trading derivatives ($38 million) and decreased cash provided by net regulatory assets and liabilities ($39 million), which was partially offset by increased distributions from equity method investments ($176 million) and increased cash provided by net accounts receivable/payable ($140 million).

Cash Used in Investing Activities

Net cash used in investing activities increased $3 million in 2015 compared to 2014 primarily due to increased capital expenditures ($212 million), which were partially offset by a return of capital from unconsolidated affiliates ($148 million), increased proceeds from sale of marketable securities ($32 million) and decreased restricted cash ($19 million).

Net cash used in investing activities increased $84 million in 2014 compared to 2013 primarily due to increased capital expenditures ($86 million), increased restricted cash ($24 million) and decreased proceeds from sale of marketable securities ($9 million), which were partially offset by decreased cash contributed to Enable ($38 million).

Cash Provided by (Used in) Financing Activities

Net cash used in financing activities increased $589 million in 2015 compared to 2014 primarily due to decreased proceeds from long-term debt ($600 million), increased payments of long-term debt ($107 million), increased distributions to ZENS holders ($32 million), decreased short-term borrowings ($23 million), increased payments of common stock dividends ($18 million) and decreased proceeds from commercial paper ($11 million), which were partially offset by increased borrowings under our revolving credit facility ($200 million).

Net cash provided by financing activities increased $828 million in 2014 compared to 2013 primarily due to decreased payments of long-term debt ($1,036 million) and increased proceeds from commercial paper ($296 million), which were partially offset by decreased proceeds from long-term debt ($450 million) and increased payments of common stock dividends ($53 million).

Future Sources and Uses of Cash

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 $1.4 billion;
- scheduled principal payments on transition and system restoration bonds of $391 million;
- investment in Enable's Series A Preferred Units of $363 million;
- maturing senior notes of $325 million;
- acquisition of the retail commercial and industrial businesses of Continuum for $77.5 million plus working capital;and
- dividend payments on CenterPoint Energy common stock and interest payments on debt.

We expect that anticipated 2016 cash needs will be met with borrowings under our credit facilities, proceeds from commercial paper, proceeds from the issuance of general mortgage bonds, anticipated cash flows from operations and distributions from Enable and Enable's redemption of $363 million of notes owed to a wholly-owned subsidiary of CERC Corp. Discretionary financing or refinancing may result in the issuance of equity or debt securities in the capital markets or the arrangement of additional credit facilities. Issuances of equity or 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)					
Electric Transmission & Distribution	$934	$833	$786	$735	$685	$686
Natural Gas Distribution	601	485	470	435	430	430
Energy Services	5	5	26	—	1	—
Other Operations	35	39	33	28	25	26
Total	$1,575	$1,362	$1,315	$1,198	$1,141	$1,142

Our capital expenditures are expected to be used for investment in infrastructure for our electric transmission and distribution operations and 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:

Contractual Obligations	Total	2016	2017-2018	2019-2020	2021 and thereafter
	(in millions)				
Transition and system restoration bond debt	$2,674	$391	$845	$689	$749
Other long-term debt (1)	6,648	325	1,150	1,135	4,038
Interest payments — transition and system restoration bond debt (2)	367	95	146	76	50
Interest payments — other long-term debt (2)	3,639	290	504	406	2,439
Short-term borrowings	40	40	—	—	—
Capital leases	3	3	—	—	—
Operating leases (3)	24	5	7	5	7
Benefit obligations (4)	—	—	—	—	—
Non-trading derivative liabilities	16	11	5	—	—
Other commodity commitments (5)	1,685	478	862	307	38
Total contractual cash obligations (6)	$15,096	$1,638	$3,519	$2,618	$7,321

(1) 2.0% Zero-Premium Exchangeable Subordinated Notes due 2029 (ZENS) obligations are included in the 2021 and thereafter column at their contingent principal amount as of December 31, 2015 of $705 million. These obligations are exchangeable for cash at any time at the option of the holders for 95% of the current value of the reference shares attributable to each ZENS ($805 million as of December 31, 2015), as discussed in Note 10 to our consolidated financial statements.

(2) 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.

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

(4) In 2016, we are not required to make contributions to our qualified pension plan. We expect to contribute approximately $8 million and $16 million, respectively, to our non-qualified pension and postretirement benefits plans in 2016.

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

(6) 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 $195 million as of December 31, 2015. See Note 3(c) to our consolidated financial statements.

Off-Balance Sheet Arrangements

Prior to the distribution of our ownership in Reliant Resources, Inc. (RRI) to our 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 Energy, Inc. (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 provided as security may be insufficient to satisfy CERC's obligations.

CenterPoint Energy has provided guarantees (CenterPoint Midstream Guarantees) with respect to the performance of certain obligations of Enable under long-term gas gathering and treating agreements with an indirect, wholly-owned subsidiary of Encana Corporation (Encana) and an indirect, wholly-owned subsidiary of Royal Dutch Shell plc (Shell). Under the terms of the omnibus agreement entered into in connection with the closing of the formation of Enable, Enable and CenterPoint Energy have agreed to use commercially reasonable efforts and cooperate with each other to terminate the CenterPoint Midstream Guarantees and to release CenterPoint Energy from such guarantees by causing Enable or one of its subsidiaries to enter into substitute guarantees or to assume the CenterPoint Midstream Guarantees as applicable. The guarantee in favor of the indirect, wholly-owned subsidiary of Encana was released on August 24, 2015. As of December 31, 2015, CenterPoint Energy had guaranteed Enable's obligations up to an aggregate amount of $50 million under the guarantee in favor of the indirect, wholly-owned subsidiary of Shell.

CERC Corp. has 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 senior debt of CERC Corp. 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

CenterPoint Houston

Brazos Valley Connection Project. In July 2013, CenterPoint Houston and other transmission service providers submitted analyses and transmission proposals to ERCOT for an additional transmission path into the Houston region. In April 2014, ERCOT's Board of Directors voted to endorse a Houston region transmission project and deemed its completion before June 2018 critical for reliability. The project will consist of (i) construction of a new double-circuit 345 kilovolt (kV) line spanning approximately 130 miles, (ii) upgrades to three substations to accommodate new connections and additional capacity, and (iii) improvements to approximately 11 miles of an existing 345 kV TH Wharton-Addicks transmission line to increase its rating. Also in April 2014, ERCOT staff determined that CenterPoint Houston would be the designated transmission service provider for the portion of the project between our Zenith substation and the Gibbons Creek substation owned by the Texas Municipal Power Agency, consisting of approximately 60–78 miles (depending on the route approved by the Texas Utility Commission) of 345 kV transmission line, upgrades to the Limestone and Zenith substations and upgrades to 11 miles of the 345 kV TH Wharton-Addicks transmission line (this portion of the Houston region transmission project is referred to by CenterPoint Houston as the Brazos Valley Connection). Other transmission service providers were designated by ERCOT for the portion of the project from the Gibbons Creek Substation to the Limestone Substation as well as the upgrades to the Gibbons Creek Substation. In April 2015, CenterPoint Houston filed a CCN application with the Texas Utility Commission seeking approval to construct the Brazos Valley Connection. CenterPoint Houston proposed 32 alternative routes for the project in the application, including the Recommended Route that CenterPoint Houston identified in the application as best meeting the routing criteria used by the Texas Utility Commission in the route selection portion of CCN proceedings. The hearing on CenterPoint Houston's CCN application was divided into two phases, a route-selection phase and a need phase. The route selection hearing was held on August 17 and 18, 2015. The hearing on the need for the line was held on September 2 and 3, 2015. On January 15, 2016, the Texas Utility Commission issued an order finding that the evidence presented by CenterPoint Houston, ERCOT, and others established the need for the project and approving a CCN for CenterPoint Houston to construct the Brazos Valley Connection using a modified version of the Recommended Route. A request for rehearing was filed with respect to the Texas Utility Commission's route selection decision. That request for rehearing will automatically be deemed denied by operation of law on March 10, 2016, unless the Texas Utility Commission acts on the request before that date. No party filed a request for rehearing on the order's need decision before the deadline expired and, therefore, that decision is final and not appealable. The Texas Utility Commission's order provided an estimated range of approximately \$270–\$310 million for the capital costs for the Brazos Valley Connection. The actual cost will depend on factors including land acquisition costs, material and construction costs and landowner elections permitted under the Texas Utility Commission's order. CenterPoint Houston expects to complete construction of the Brazos Valley Connection by mid-2018.

In May 2014, several electric generators appealed the ERCOT Board of Directors' April 2014 approval of the Houston region transmission project and the determination that the project was critical for reliability in the Houston region to the Texas Utility Commission. That appeal was denied by the Texas Utility Commission in December 2014. In March 2015, the electric generators petitioned the Texas District Court of Travis County for judicial review of the Texas Utility Commission's denial of their appeal. That case is currently pending before that court.

Transmission Cost of Service. On November 21, 2014, CenterPoint Houston filed an application, as amended, with the Texas Utility Commission seeking an increase in annual transmission revenues based on an incremental increase in total rate base of

$113.2 million. CenterPoint Houston received approval from the Texas Utility Commission during the first quarter of 2015, and rates became effective February 25, 2015, resulting in an increase of $23.5 million in annual transmission revenues.

On June 26, 2015, CenterPoint Houston filed an application with the Texas Utility Commission for an interim update of its TCOS seeking an increase in annual transmission revenues based on an incremental increase of $87.6 million in total rate base. The Texas Utility Commission approved CenterPoint Houston’s application in the third quarter of 2015, and rates became effective August 17, 2015, resulting in an increase of $13.7 million in annual transmission revenues.

On October 1, 2015, CenterPoint Houston filed an application with the Texas Utility Commission for an interim update of its TCOS seeking an increase in annual transmission revenues based on an incremental increase of $107.6 million in total rate base. The Texas Utility Commission approved CenterPoint Houston’s application in the fourth quarter of 2015, and rates became effective November 23, 2015, resulting in an increase of $16.8 million in annual transmission revenue.

Distribution Cost Recovery Factor. On April 6, 2015, CenterPoint Houston filed an application with the Texas Utility Commission for a DCRF interim rate adjustment to account for changes in certain distribution-invested capital since its 2010 rate case. The application requested (i) an increase in annual distribution revenue of $16.7 million based on an increase in rate base from January 1, 2010 through December 31, 2014 of $417 million; and (ii) that rates become effective September 1, 2015.

The DCRF application must be filed between April 1 and April 8 of any given year. The application includes recovery of specific incremental distribution-related invested capital, including poles, transformers, conductors, meters and telecommunication equipment from the previous rate case to the end of the DCRF update period, less an adjustment for the related accumulated deferred income taxes. The application includes recovery of return on investment, depreciation expense, federal income tax, and other associated taxes less an adjustment for changes in customer count and weather normalized usage during the update period. The allocation to customer classes is conducted in the same manner as current rates. Any authorized rate change is applied to all retail customers on an energy or demand charge basis, effective September 1, 2015, through a separate DCRF charge. Only four DCRF changes may be implemented between rate cases. The utility must file an earnings monitoring report (EMR) annually with the DCRF application. By law, a DCRF application will be denied if the EMR shows the utility is earning more than its authorized rate of return using 10-year weather normalized data.

On June 19, 2015, an unopposed settlement agreement was filed providing for an increase in annual distribution revenue of $13.0 million, subject to final Texas Utility Commission approval. The Texas Utility Commission approved the settlement agreement on July 30, 2015. Rates became effective September 1, 2015.

Energy Efficiency Cost Recovery Factor (EECRF). On June 1, 2015, CenterPoint Houston filed an application with the Texas Utility Commission for an adjustment to its EECRF to recover $37.7 million in 2016, including an incentive of $6.6 million based on 2014 program performance. In October 2015, the Texas Utility Commission approved the application to recover $37.6 million. The effective date of the rate adjustment will be March 1, 2016.

CERC

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 Facilities

As of February 12, 2016, we had the following facilities:

Execution Date	Company	Size of Facility	Amount Utilized at February 12, 2016 (1)		Termination Date
		(in millions)			
September 9, 2011	CenterPoint Energy	$1,200	$826	(2)	September 9, 2019
September 9, 2011	CenterPoint Houston	300	204	(3)	September 9, 2019
September 9, 2011	CERC Corp.	600	18	(4)	September 9, 2019

(1) Based on the consolidated debt to capitalization covenant in our revolving credit facility and the revolving credit facility of each of CenterPoint Houston and CERC Corp., we would have been permitted to utilize the full capacity of such revolving credit facilities, which aggregated $2.1 billion at December 31, 2015.

(2) Represents outstanding commercial paper of $820 million and outstanding letters of credit of $6 million.

(3) Represents outstanding letters of credit of $4 million and outstanding bank loans of $200 million.

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

Our $1.2 billion revolving credit facility can be drawn at the London Interbank Offered Rate (LIBOR) plus 1.25% based on our current credit ratings. The revolving credit facility contains a financial covenant which limits our consolidated debt (excluding transition and system restoration bonds) to an amount not to exceed 65% of our consolidated capitalization. As of December 31, 2015, our debt (excluding transition and system restoration bonds) to capital ratio, as defined in our credit facility agreement, was 55.1%. The financial covenant limit will temporarily increase from 65% to 70% if CenterPoint Houston experiences damage from a natural disaster in its service territory and we certify to the administrative agent that CenterPoint Houston has incurred system restoration costs reasonably likely to exceed $100 million in a consecutive twelve-month period, all or part of which CenterPoint Houston intends to seek to recover through securitization financing. Such temporary increase in the financial covenant would be in effect from the date we deliver our certification until the earliest to occur of (i) the completion of the securitization financing, (ii) the first anniversary of our certification or (iii) the revocation of such certification.

CenterPoint Houston's $300 million revolving credit facility can be drawn at LIBOR plus 1.125% based on CenterPoint Houston's current credit ratings. The revolving credit facility contains a financial covenant which limits CenterPoint Houston's consolidated debt (excluding transition and system restoration bonds) to an amount not to exceed 65% of CenterPoint Houston's consolidated capitalization. As of December 31, 2015, CenterPoint Houston's debt (excluding transition and system restoration bonds) to capital ratio, as defined in its credit facility agreement, was 51.7%.

CERC Corp.'s $600 million revolving credit facility can be drawn at LIBOR plus 1.5% 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%.

Borrowings under each of the three revolving credit facilities are subject to customary terms and conditions. However, there is no requirement that the borrower 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 each of the revolving credit facilities are subject to acceleration upon the occurrence of events of default that we consider customary. The revolving credit facilities also provide for customary fees, including commitment fees, administrative agent fees, fees in respect of letters of credit and other fees. In each of the three revolving credit facilities, the spread to LIBOR and the commitment fees fluctuate based on the borrower's credit rating. The borrowers are currently in compliance with the various business and financial covenants in the three revolving credit facilities.

Our $1.2 billion revolving credit facility backstops our $1.0 billion commercial paper program. As of December 31, 2015, we had $716 million of outstanding commercial paper with a weighted average interest rate of 0.79%. 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%.

In November 2015, we retired $740 million of tax-exempt municipal bonds that had been held for remarketing.

Securities Registered with the SEC

CenterPoint Energy, CenterPoint Houston and CERC Corp. have filed a joint shelf registration statement with the SEC registering indeterminate principal amounts of CenterPoint Houston's general mortgage bonds, CERC Corp.'s senior debt securities and CenterPoint Energy's senior debt securities and junior subordinated debt securities and an indeterminate number of CenterPoint Energy's shares of common stock, shares of preferred stock, as well as stock purchase contracts and equity units.

Temporary Investments

As of February 12, 2016, we had no temporary investments.

Money Pool

We have a money pool through which the holding company and participating subsidiaries 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 our revolving credit facility or the sale of our commercial paper.

Impact on Liquidity of a Downgrade in Credit Ratings

The interest on borrowings under our credit facilities 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 senior debt of CenterPoint Energy and certain subsidiaries:

Company/Instrument	Moody's Rating	Outlook (1)	S&P Rating	Outlook (2)	Fitch Rating	Outlook (3)
CenterPoint Energy Senior Unsecured Debt	Baa1	Stable	BBB+	Negative	BBB	Stable
CenterPoint Houston Senior Secured Debt	A1	Stable	A	Negative	A	Stable
CERC Corp. Senior Unsecured Debt	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 $1.2 billion revolving credit facility, CenterPoint Houston's $300 million revolving credit facility and CERC Corp.'s $600 million revolving credit facility. If our credit ratings or those of CenterPoint Houston or CERC Corp. 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 the three revolving credit facilities 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.

CERC Corp. and its subsidiaries purchase natural gas from one of their 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, CERC 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, a wholly-owned subsidiary of CERC Corp. 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.

In September 1999, we issued ZENS having an original principal amount of $1.0 billion of which $828 million remains outstanding at December 31, 2015. Each ZENS note was originally exchangeable at the holder's option at any time for an amount of cash equal to 95% of the market value of the reference shares of TW Common attributable to such note. The number and identity of the reference shares attributable to each ZENS note are adjusted for certain corporate events. Prior to the closing of the merger discussed below, the reference shares for each ZENS note consisted of 0.5 share of TW Common, 0.125505 share of TWC Common, 0.045455 share of AOL Common and 0.0625 share of Time Common.

On May 26, 2015, Verizon initiated a tender offer to purchase all outstanding shares of AOL Common for $50 per share, in which we tendered all of our shares of AOL Common for $32 million. Verizon acquired the remaining eligible shares through a merger, which closed on June 23, 2015. In accordance with the terms of the ZENS, we remitted $32 million to ZENS holders in July 2015, which reduced contingent principal. As a result, we recorded a reduction in the indexed debt securities derivative liability of $18 million, a reduction in the indexed debt balance of $7 million and a loss of $7 million, which is included in Gain (loss) on indexed debt securities on the Statements of Consolidated Income. As of December 31, 2015, the reference shares for each ZENS note consisted of 0.5 share of TW Common, 0.125505 share of TWC Common and 0.0625 share of Time Common, and the contingent principal balance was $705 million.

On May 26, 2015, Charter Communications, Inc. (Charter) announced that it had entered into a definitive merger agreement with TWC. On September 21, 2015, Charter shareholders approved the announced transaction with TWC. Pursuant to the merger agreement, upon closing of the merger, TWC Common shares would be exchanged for cash and Charter stock and as a result, reference shares would consist of Charter stock, TW Common and Time Common. The merger is expected to close by June of 2016.

If our creditworthiness were to drop such that ZENS note holders thought our liquidity was adversely affected or the market for the ZENS notes were to become illiquid, some ZENS note holders might decide to exchange their ZENS notes for cash. Funds for the payment of cash upon exchange could be obtained from the sale of the shares of TW Common, TWC Common and Time Common that we own or from other sources. We own shares of TW Common, TWC Common and Time Common equal to approximately 100% of the reference shares used to calculate our obligation to the holders of the ZENS notes. ZENS note exchanges result in a cash outflow because tax deferrals related to the ZENS notes and TW Common, TWC Common and Time Common shares would typically cease when ZENS notes are exchanged or otherwise retired and TW Common, TWC Common and Time Common shares are sold. The ultimate tax liability related to the ZENS notes continues to increase by the amount of the tax benefit realized each year, and there could be a significant cash outflow when the taxes are paid as a result of the retirement of the ZENS notes. If all ZENS notes had been exchanged for cash on December 31, 2015, deferred taxes of approximately $450 million would have been payable in 2015. If all the TW Common, TWC Common and Time Common had been sold on December 31, 2015, capital gains taxes of approximately $236 million would have been payable in 2015.

Cross Defaults

Under our 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 or any of our significant subsidiaries will cause a default. A default by CenterPoint Energy would not trigger a default under our subsidiaries' debt instruments or revolving credit facilities.

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 and/or equity issuances. Debt or equity 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, and exploring the use of the real estate investment trust business model for all or part of our utility businesses. There can be no assurances that this evaluation will result in any specific action, and we do not intend to disclose further developments on these initiatives unless and until our 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 CERC Corp. were obligated on approximately $363 million of indebtedness owed to a wholly-owned subsidiary of CERC Corp.

On January 28, 2016, we entered into a purchase agreement with Enable pursuant to which we 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 a wholly-owned subsidiary of CERC Corp. We used the proceeds from this redemption for our 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 9 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 and electric operations in Texas do not have such mechanisms, although fixed customer charges are historically higher in Texas for NGD compared to our other jurisdictions. As a result, fluctuations from normal weather may have a positive or negative effect on NGD’s results in Texas and on CenterPoint Houston’s results in its service territory. 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. We entered into a weather hedge for CenterPoint Houston’s service territory for the 2015–2016 winter season.

Collection of Receivables from REPs

CenterPoint Houston’s receivables from the distribution of electricity are collected from REPs that supply the electricity CenterPoint Houston distributes to their customers. Adverse economic conditions, structural problems in the market served by ERCOT or financial difficulties of one or more REPs could impair the ability of these REPs to pay for CenterPoint Houston’s services or could cause them to delay such payments. CenterPoint Houston depends on these REPs to remit payments on a timely basis, and any delay or default in payment by REPs could adversely affect CenterPoint Houston’s cash flows. In the event of a REP’s default, CenterPoint Houston’s tariff provides a number of remedies, including the option for CenterPoint Houston to request that the Texas Utility Commission suspend or revoke the certification of the REP. Applicable regulatory provisions require that customers be shifted to another REP or a provider of last resort if a REP cannot make timely payments. However, CenterPoint Houston remains at risk for payments related to services provided prior to the shift to the replacement REP or the provider of last resort. If a REP were unable to meet its obligations, it could consider, among various options, restructuring under the bankruptcy laws, in which event such REP might seek to avoid honoring its obligations, and claims might be made against CenterPoint Houston involving payments it had received from such REP. If a REP were to file for bankruptcy, CenterPoint Houston may not be successful in recovering accrued receivables owed by such REP that are unpaid as of the date the REP filed for bankruptcy. However, Texas Utility Commission regulations authorize utilities, such as CEHE, to defer bad debts resulting from defaults by REPs for recovery in future rate cases, subject to a review of reasonableness and necessity.

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 us and our subsidiaries or in connection with the contractual obligations to a third party pursuant to which our subsidiary is their guarantor;
- the ability of REPs, including REP affiliates of NRG and Energy Future Holdings Corp., to satisfy their obligations to us and our subsidiaries;
- slower customer payments and increased write-offs of receivables due to higher gas prices or changing economic conditions;
- the outcome of litigation brought by and against us;
- contributions to pension and postretirement benefit plans;
- restoration costs and revenue losses resulting from future natural disasters such as hurricanes and the timing of recovery of such restoration costs; and
- various other risks identified in "Risk Factors" in Item 1A of Part I of this report.

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

CenterPoint Houston's revolving credit facility limits CenterPoint Houston's consolidated debt (excluding transition and system restoration bonds) to an amount not to exceed 65% of its consolidated capitalization. CERC Corp.'s revolving credit facility limits CERC's consolidated debt to an amount not to exceed 65% of its consolidated capitalization. Our revolving credit facility limits our consolidated debt (excluding transition and system restoration bonds) to an amount not to exceed 65% of our consolidated capitalization. The financial covenant limit in our revolving credit facility will temporarily increase from 65% to 70% if CenterPoint Houston experiences damage from a natural disaster in its service territory that meets certain criteria. Additionally, CenterPoint Houston has contractually agreed that it will not issue additional first mortgage bonds, subject to certain exceptions.

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.

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 Electric Transmission & Distribution business segment and our Natural Gas Distribution business segment apply 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 $3.1 billion and regulatory liabilities of $1.3 billion.

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 8 and 9 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, respectively, 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 electricity delivery and 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 either electronically through advanced metering system (AMS) meter communications or manual readings. At the end of each month, deliveries to non-AMS customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. Information regarding deliveries to AMS customers after the last billing is obtained from actual AMS meter usage data. Unbilled electricity delivery revenue is estimated each month based on actual AMS meter data, daily supply volumes and applicable rates. 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.

Pension and Other Retirement Plans

We sponsor pension and other retirement plans in various forms covering all employees who meet eligibility requirements. We use several statistical and other factors that attempt to anticipate future events in calculating the expense and liability related to our plans. These factors include assumptions about the discount rate, expected return on plan assets and rate of future compensation increases as estimated by management, within certain guidelines. In addition, our actuarial consultants use subjective factors such as withdrawal and mortality rates. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. These differences may result in a significant impact to the amount of pension expense recorded. Please read "— Other Significant Matters — Pension Plans" for further discussion.

NEW ACCOUNTING PRONOUNCEMENTS

See Note 2(o) to our consolidated financial statements for a discussion of new accounting pronouncements that affect us.

OTHER SIGNIFICANT MATTERS

Pension Plans. As discussed in Note 6(b) to our consolidated financial statements, we maintain a non-contributory qualified defined benefit pension plan covering substantially all employees. Employer contributions for the qualified plan are based on actuarial computations that establish the minimum contribution required under the Employee

Retirement Income Security Act of 1974 (ERISA) and the maximum deductible contribution for income tax purposes.

Under the terms of our pension plan, we reserve the right to change, modify or terminate the plan. Our funding policy is to review amounts annually and contribute an amount at least equal to the minimum contribution required under ERISA.

The minimum funding requirements for the qualified pension plan were $-0-, $87 million and $83 million for 2015, 2014 and 2013, respectively. We made contributions of $35 million, $87 million and $83 million in 2015, 2014 and 2013 for the respective years. We are not required to make any contribution in 2016.

Additionally, we maintain an unfunded non-qualified benefit restoration plan that allows participants to receive the benefits to which they would have been entitled under our non-contributory pension plan except for the federally mandated limits on qualified plan benefits or on the level of compensation on which qualified plan benefits may be calculated. Employer contributions for the non-qualified benefit restoration plan represent benefit payments made to participants and totaled $31 million, $10 million and $8 million in 2015, 2014 and 2013, respectively. We expect to make contributions aggregating approximately $8 million in 2016.

Changes in pension obligations and assets may not be immediately recognized as pension expense in the income statement, but generally are recognized in future years over the remaining average service period of plan participants. As such, significant portions of pension expense recorded in any period may not reflect the actual level of benefit payments provided to plan participants.

As the sponsor of a plan, we are required to (a) recognize on our balance sheet as an asset a plan's over-funded status or as a liability such plan's under-funded status, (b) measure a plan's assets and obligations as of the end of our fiscal year and (c) recognize changes in the funded status of our plans in the year that changes occur through adjustments to other comprehensive income and regulatory assets.

The projected benefit obligation for all defined benefit pension plans was $2,193 million and $2,403 million as of December 31, 2015 and 2014, respectively. The adoption of the new mortality table by the Society of Actuaries as of December 31, 2014 significantly contributed to the increase in the projected benefit obligation for 2014.

As of December 31, 2015, the projected benefit obligation exceeded the market value of plan assets of our pension plans by $514 million. Changes in interest rates or the market values of the securities held by the plan during 2016 could materially, positively or negatively, change our funded status and affect the level of pension expense and required contributions.

Pension cost was $90 million, $77 million and $72 million for 2015, 2014 and 2013, respectively, of which $59 million, $71 million and $64 million impacted pre-tax earnings, respectively. Included in the 2015 and 2014 pension costs were a $10 million settlement charge and $6 million curtailment loss, respectively, as discussed below.

A one-time, non-cash settlement charge is required when lump sum distributions or other settlements of plan benefit obligations during the year exceed the service cost and interest cost components of net periodic cost for the year. Due to the amount of lump sum payment distributions from the non-qualified pension plan during the year ended December 31, 2015, CenterPoint Energy recognized a non-cash settlement charge of $10 million. This charge is an acceleration of costs that would otherwise be recognized in future periods.

During the fourth quarter of 2014, CenterPoint Energy received notification from Enable of its intent to provide employment offers to substantially all seconded employees. As a result, an additional pension cost of $6 million was recognized for the curtailment loss related to our pension plans. Substantially all of the seconded employees became employees of Enable effective January 1, 2015.

The calculation of pension expense and related liabilities requires the use of assumptions. Changes in these assumptions can result in different expense and liability amounts, and future actual experience can differ from the assumptions. Two of the most critical assumptions are the expected long-term rate of return on plan assets and the assumed discount rate.

As of December 31, 2015, our qualified pension plan had an expected long-term rate of return on plan assets of 6.25%, which is a 0.25% decrease from the rate assumed as of December 31, 2014 due to lower expected capital market return rates. The expected rate of return assumption was developed using the targeted asset allocation of our plans and the expected return for each asset class. We regularly review our actual asset allocation and periodically rebalance plan assets to reduce volatility and better match plan assets and liabilities.

As of December 31, 2015, the projected benefit obligation was calculated assuming a discount rate of 4.40%, which is 0.35% higher than the 4.05% discount rate assumed in 2014. The discount rate was determined by reviewing yields on high-quality bonds that receive one of the two highest ratings given by a recognized rating agency and the expected duration of pension obligations specific to the characteristics of our plan.

Pension cost for 2016, including the benefit restoration plan, is estimated to be $102 million, of which we expect $66 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. If the expected return assumption were lowered by 0.50% from 6.25% to 5.75%, 2016 pension cost would increase by approximately $8 million.

As of December 31, 2015, the pension plan projected benefit obligation, including the unfunded benefit restoration plan, exceeded plan assets by $514 million. If the discount rate were lowered by 0.50% from 4.40% to 3.90%, the assumption change would increase our projected benefit obligation by approximately $115 million and decrease our 2016 pension expense by approximately $2 million. The expected reduction in pension expense due to the decrease in discount rate is a result of the expected correlation between the reduced interest rate and appreciation of fixed income assets in pension plans with significantly more fixed income instruments than equity instruments. In addition, the assumption change would impact our Consolidated Balance Sheet by increasing the regulatory asset recorded as of December 31, 2015 by $101 million and would result in a charge to comprehensive income in 2015 of $9 million, net of tax.

Future changes in plan asset returns, assumed discount rates and various other factors related to the pension plan 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, Equity Prices 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, interest rates and equity prices. 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.

- Equity price risk results from exposures to changes in prices of individual equity securities.

- 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, lease obligations and obligations under our ZENS that subject us to the risk of loss associated with movements in market interest rates.

Our floating rate obligations aggregated $1.1 billion and $532 million as of 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 $1 million annually.

As of December 31, 2015 and 2014, we had outstanding fixed-rate debt (excluding indexed debt securities) aggregating $7.5 billion and $8.2 billion, respectively, in principal amount and having a fair value of $8.0 billion and $8.9 billion, respectively. Because these instruments are fixed-rate, they do not expose us to the risk of loss in earnings due to changes in market interest rates (see Note 12 to our consolidated financial statements). However, the fair value of these instruments would increase by approximately $216 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.

As discussed in Note 10 to our consolidated financial statements, the ZENS obligation is bifurcated into a debt component and a derivative component. The debt component of $154 million at December 31, 2015 was a fixed-rate obligation and, therefore, did not expose us to the risk of loss in earnings due to changes in market interest rates. However, the fair value of the debt component would increase by approximately $24 million if interest rates were to decline by 10% from levels at December 31, 2015. Changes in the fair value of the derivative component, a $442 million recorded liability at December 31, 2015, are recorded in our Statements of Consolidated Income and, therefore, we are exposed to changes in the fair value of the derivative component as a result of changes in the underlying risk-free interest rate. If the risk-free interest rate were to increase by 10% from December 31, 2015 levels, the fair value of the derivative component liability would increase by approximately $8 million, which would be recorded as an unrealized loss in our Statements of Consolidated Income.

Equity Market Value Risk

We are exposed to equity market value risk through our ownership of 7.1 million shares of TW Common, 1.8 million shares of TWC Common and 0.9 million shares of Time Common, which we hold to facilitate our ability to meet our obligations under the ZENS. See Note 10 to our consolidated financial statements for a discussion of our ZENS obligation. A decrease of 10% from the December 31, 2015 aggregate market value of these shares would result in a net loss of approximately $14 million, which would be recorded as an unrealized loss in our Statements of Consolidated Income.

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 Board of Directors and Shareholders of
CenterPoint Energy, Inc.
Houston, Texas

We have audited the accompanying consolidated balance sheets of CenterPoint Energy, Inc. and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related statements of consolidated income, comprehensive income, shareholders' 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes 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, Inc. 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.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, based on the criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2016 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 26, 2016

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED INCOME

	Year Ended December 31,		
	2015	2014	2013
	(in millions, except per share amounts)		
Revenues	$7,386	$9,226	$8,106
Expenses:			
Natural gas	3,102	4,921	3,908
Operation and maintenance	2,007	1,969	1,847
Depreciation and amortization	970	1,013	954
Taxes other than income taxes	374	388	387
Total	6,453	8,291	7,096
Operating Income	933	935	1,010
Other Income (Expense):			
Gain (Loss) on marketable securities	(93)	163	236
Gain (Loss) on indexed debt securities	74	(86)	(193)
Interest and other finance charges	(352)	(353)	(351)
Interest on transition and system restoration bonds	(105)	(118)	(133)
Equity in earnings (losses) of unconsolidated affiliates	(1,633)	308	188
Other, net	46	36	24
Total	(2,063)	(50)	(229)
Income (Loss) Before Income Taxes	(1,130)	885	781
Income tax expense (benefit)	(438)	274	470
Net Income (Loss)	$(692)	$611	$311
Basic Earnings (Loss) Per Share	$(1.61)	$1.42	$0.73
Diluted Earnings (Loss) Per Share	$(1.61)	$1.42	$0.72
Weighted Average Shares Outstanding, Basic	430	430	428
Weighted Average Shares Outstanding, Diluted	430	432	431

See Notes to Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME

	Year Ended December 31,		
	2015	2014	2013
	(in millions)		
Net income (loss)	$(692)	$611	$311
Other comprehensive income:			
Adjustment to pension and other postretirement plans (net of tax of $12, $5 and $25, respectively)	20	3	44
Reclassification of deferred loss from cash flow hedges realized in net income (net of tax)	—	1	1
Other comprehensive income	20	4	45
Comprehensive income (loss)	$(672)	$615	$356

See Notes to Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2015	December 31, 2014
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents ($264 and $290 related to VIEs, respectively)	$264	$298
Investment in marketable securities	805	930
Accounts receivable ($64 and $58 related to VIEs, respectively), less bad debt reserve of $20 and $26, respectively	593	837
Accrued unbilled revenues	279	357
Inventory	347	379
Non-trading derivative assets	89	99
Taxes receivable	172	190
Prepaid expense and other current assets ($35 and $47 related to VIEs, respectively)	140	178
Total current assets	2,689	3,268
Property, Plant and Equipment, net	11,537	10,502
Other Assets:		
Goodwill	840	840
Regulatory assets ($2,373 and $2,738 related to VIEs, respectively)	3,129	3,527
Notes receivable - affiliated companies	363	363
Non-trading derivative assets	36	32
Investment in unconsolidated affiliates	2,594	4,521
Other	146	147
Total other assets	7,108	9,430
Total Assets	$21,334	$23,200
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Short-term borrowings	$40	$53
Current portion of VIE transition and system restoration bonds long-term debt	391	372
Indexed debt	154	152
Current portion of other long-term debt	328	271
Indexed debt securities derivative	442	541
Accounts payable	483	716
Taxes accrued	158	161
Interest accrued	117	124
Non-trading derivative liabilities	11	19
Other	343	383
Total current liabilities	2,467	2,792
Other Liabilities:		
Deferred income taxes, net	5,047	5,440
Non-trading derivative liabilities	5	1
Benefit obligations	904	953
Regulatory liabilities	1,276	1,206
Other	273	251
Total other liabilities	7,505	7,851
Long-term Debt:		
VIE transition and system restoration bonds	2,283	2,674

Other long-term debt	5,618	5,335
Total long-term debt	7,901	8,009
Commitments and Contingencies (Note 14)		
Shareholders’ Equity	3,461	4,548
Total Liabilities and Shareholders’ Equity	$21,334	$23,200

See Notes to Consolidated Financial Statements

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CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED CASH FLOWS

	Year Ended December 31,		
	2015	2014	2013
	(in millions)		
Cash Flows from Operating Activities:			
Net income (loss)	$(692)	$611	$311
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	970	1,013	954
Amortization of deferred financing costs	27	28	30
Deferred income taxes	(413)	280	356
Unrealized loss (gain) on marketable securities	93	(163)	(236)
Loss (gain) on indexed debt securities	(74)	86	193
Write-down of natural gas inventory	4	8	4
Equity in (earnings) losses of unconsolidated affiliates, net of distributions	1,779	(2)	(58)
Pension contributions	(66)	(97)	(91)
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues, net	345	39	(256)
Inventory	28	(102)	(22)
Taxes receivable	18	(190)	7
Accounts payable	(224)	(3)	152
Fuel cost recovery	43	(41)	108
Non-trading derivatives, net	(7)	(34)	4
Margin deposits, net	(4)	(79)	16
Interest and taxes accrued	(10)	(23)	41
Net regulatory assets and liabilities	63	22	61
Other current assets	10	1	(2)
Other current liabilities	(50)	(20)	21
Other assets	(5)	9	(24)
Other liabilities	8	41	20
Other, net	22	13	24
Net cash provided by operating activities	1,865	1,397	1,613
Cash Flows from Investing Activities:			
Capital expenditures	(1,584)	(1,372)	(1,286)
Distributions from unconsolidated affiliates in excess of cumulative earnings	148	—	—
Decrease (increase) in restricted cash of transition and system restoration bond companies	12	(7)	17
Investment in unconsolidated affiliates	—	(1)	—
Cash contribution to Enable	—	—	(38)
Proceeds from sale of marketable securities	32	—	9
Other, net	5	(4)	(2)
Net cash used in investing activities	(1,387)	(1,384)	(1,300)
Cash Flows from Financing Activities:			
Increase (decrease) in short-term borrowings, net	(13)	10	5
Proceeds from commercial paper, net	403	414	118
Proceeds from long-term debt	—	600	1,050
Payments of long-term debt	(644)	(537)	(1,573)
Long-term revolving credit facility	200	—	—

Cash paid for debt exchange and debt retirement	—	(1)	(7)
Debt issuance costs	—	(8)	(3)
Redemption of indexed debt securities	—	—	(8)
Payment of common stock dividends	(426)	(408)	(355)
Proceeds from issuance of common stock, net	—	1	4
Distribution to ZENS holders	(32)	—	—
Other, net	—	6	18
Net cash provided by (used in) financing activities	(512)	77	(751)
Net Increase (Decrease) in Cash and Cash Equivalents	(34)	90	(438)
Cash and Cash Equivalents at Beginning of Year	298	208	646
Cash and Cash Equivalents at End of Year	$264	$298	$208

See Notes to Consolidated Financial Statements

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CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED CASH FLOWS, cont.

	Year Ended December 31,		
	2015	2014	2013
	(in millions)		
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest, net of capitalized interest	$426	$434	$475
Income taxes (refunds), net	(45)	192	35
Non-cash transactions:			
Accounts payable related to capital expenditures	95	104	74
Formation of Enable	—	—	4,252
Exercise of SESH put to Enable	1	196	—

See Notes to Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED SHAREHOLDERS' EQUITY

	2015		2014		2013	
	Shares	Amount	Shares	Amount	Shares	Amount
	(in millions of dollars and shares)					
Preference Stock, none outstanding	—	$—	—	$—	—	$—
Cumulative Preferred Stock, $0.01 par value; authorized 20,000,000 shares, none outstanding	—	—	—	—	—	—
Common Stock, $0.01 par value; authorized 1,000,000,000 shares						
Balance, beginning of year	430	4	429	4	428	4
Issuances related to benefit and investment plans	—	—	1	—	1	—
Balance, end of year	430	4	430	4	429	4
Additional Paid-in-Capital						
Balance, beginning of year		4,169		4,157		4,130
Issuances related to benefit and investment plans		11		12		27
Balance, end of year		4,180		4,169		4,157
Retained Earnings (Accumulated Deficit)						
Balance, beginning of year		461		258		302
Net income (loss)		(692)		611		311
Common stock dividends		(426)		(408)		(355)
Balance, end of year		(657)		461		258
Accumulated Other Comprehensive Loss						
Balance, end of year:						
Adjustment to pension and postretirement plans		(65)		(85)		(88)
Net deferred loss from cash flow hedges		(1)		(1)		(2)
Total accumulated other comprehensive loss, end of year		(66)		(86)		(90)
Total Shareholders' Equity		$3,461		$4,548		$4,329

See Notes to Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Background

CenterPoint Energy, Inc. is a public utility holding company. CenterPoint Energy’s operating subsidiaries own and operate electric transmission and distribution facilities and natural gas distribution facilities and own interests in Enable Midstream Partners, LP (Enable) as described below. As of December 31, 2015, CenterPoint Energy’s indirect wholly-owned subsidiaries included:

- CenterPoint Energy Houston Electric, LLC (CenterPoint Houston), which engages in the electric transmission and distribution business in the Texas Gulf Coast area that includes the city of Houston; and

- 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.

For a description of CenterPoint Energy’s reportable business segments, see Note 17.

(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 CenterPoint Energy and its wholly-owned and majority owned subsidiaries are included in the consolidated financial statements. All intercompany transactions and balances are eliminated in consolidation. CenterPoint Energy generally uses the equity method of accounting for investments in entities in which CenterPoint Energy has an ownership interest between 20% and 50% and exercises significant influence. CenterPoint Energy 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, CenterPoint Energy adjusts its investment in Enable each period for contributions made, distributions received, CenterPoint Energy’s share of Enable’s comprehensive income and amortization of basis differences, as appropriate. CenterPoint Energy 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.

CenterPoint Energy'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, CenterPoint Energy 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.

As of December 31, 2015, CenterPoint Energy had VIEs consisting of transition and system restoration bond companies, which it consolidates. The consolidated VIEs are wholly-owned bankruptcy remote special purpose entities that were formed specifically for the purpose of securitizing transition and system restoration related property. Creditors of CenterPoint Energy have no recourse to any assets or revenues of the transition and system restoration bond companies. The bonds issued by these VIEs are payable only from and secured by transition and system restoration property and the bondholders have no recourse to the general credit of CenterPoint Energy.

(c) Revenues

CenterPoint Energy records revenue for electricity delivery and natural gas sales and services under the accrual method and these revenues are recognized upon delivery to customers. Electricity deliveries not billed by month-end are accrued based on actual advanced metering system data, daily supply volumes and applicable rates. 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

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

CenterPoint Energy 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

CenterPoint Energy applies the guidance for accounting for regulated operations to the Electric Transmission & Distribution business segment and the Natural Gas Distribution business segment. CenterPoint Energy'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.

CenterPoint Energy'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 $980 million and $958 million, respectively, are classified as regulatory liabilities in CenterPoint Energy's 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, CenterPoint Energy capitalized interest and AFUDC of $10 million, $11 million and $11 million, respectively. During 2015, 2014 and 2013, CenterPoint Energy recorded AFUDC equity of $12 million, $14 million and $8 million, respectively, which is included in Other Income in its Statements of Consolidated Income.

(h) Income Taxes

CenterPoint Energy uses the asset and liability method of accounting for deferred 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. CenterPoint Energy 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 CenterPoint Energy's Statements of Consolidated Income for 2015, 2014 and 2013 was $19 million, $22 million and $21 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 CenterPoint Energy's Energy Services business segment are valued at the lower of average cost or market. Natural gas inventories of CenterPoint Energy's Natural Gas Distribution business segment are primarily valued at weighted average cost. During 2015, 2014 and 2013, CenterPoint Energy 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	$179	$168
Natural gas	168	211
Total inventory	$347	$379

(k) Derivative Instruments

CenterPoint Energy is exposed to various market risks. These risks arise from transactions entered into in the normal course of business. CenterPoint Energy 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 CenterPoint Energy's Consolidated Balance Sheets at their fair value unless

CenterPoint Energy 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 CenterPoint Energy’s marketing, risk management services and hedging activities. The committee’s duties are to establish CenterPoint Energy’s commodity risk policies, allocate board-approved commercial risk limits, approve the use of new products and commodities, monitor positions and ensure compliance with CenterPoint Energy’s risk management policies and procedures and limits established by CenterPoint Energy’s board of directors.

CenterPoint Energy'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) Investments in Other Debt and Equity Securities

CenterPoint Energy reports securities classified as trading at estimated fair value in its Consolidated Balance Sheets, and any unrealized holding gains and losses are recorded as other income (expense) in its Statements of Consolidated Income.

(m) Environmental Costs

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

(n) Statements of Consolidated Cash Flows

For purposes of reporting cash flows, CenterPoint Energy considers cash equivalents to be short-term, highly-liquid investments with maturities of three months or less from the date of purchase. In connection with the issuance of transition bonds and system restoration bonds, CenterPoint Energy was required to establish restricted cash accounts to collateralize the bonds that were issued in these financing transactions. These restricted cash accounts are not available for withdrawal until the maturity of the bonds and are not included in cash and cash equivalents. These restricted cash accounts of $35 million and $47 million as of December 31, 2015 and 2014, respectively, are included in other current assets in CenterPoint Energy's Consolidated Balance Sheets. Cash and cash equivalents included $264 million and $290 million as of December 31, 2015 and 2014, respectively, that was held by CenterPoint Energy's transition and system restoration bond subsidiaries solely to support servicing the transition and system restoration bonds.

CenterPoint Energy 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. CenterPoint Energy 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.

(o) 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. CenterPoint Energy 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. CenterPoint Energy 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. CenterPoint Energy had debt issuance costs of $53 million and $61 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. CenterPoint Energy will adopt ASU 2015-05 prospectively on January 1, 2016. CenterPoint Energy 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. CenterPoint Energy 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. CenterPoint Energy 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. CenterPoint Energy adopted ASU 2015-17 retrospectively starting with fiscal year 2015. As such, certain prior period amounts have been classified to conform to the current presentation. In the Consolidated Balance Sheet as of December 31, 2014, CenterPoint Energy reclassified $683 million from current deferred income tax liabilities to increase deferred income taxes within non-current liabilities. See Note 13 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.

(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	2014
		(in millions)	
Electric Transmission & Distribution	31	$10,142	$9,393
Natural Gas Distribution	32	5,762	5,235
Energy Services	27	86	84
Other property	24	660	646
Total		16,650	15,358
Accumulated depreciation and amortization:			
Electric Transmission & Distribution		3,209	3,050
Natural Gas Distribution		1,575	1,493
Energy Services		34	31
Other property		295	282
Total accumulated depreciation and amortization		5,113	4,856
Property, plant and equipment, net		$11,537	$10,502

(b) Depreciation and Amortization

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

	2015	2014	2013
	(in millions)		
Depreciation expense	$557	$521	$531
Amortization expense	413	492	423
Total depreciation and amortization expense	$970	$1,013	$954

(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	$176	$134
Accretion expense	6	5
Revisions in estimates of cash flows	13	37
Ending balance	$195	$176

CenterPoint Energy recorded AROs associated with the removal of asbestos and asbestos-containing material in its buildings, including substation building structures. CenterPoint Energy also recorded AROs relating to gas pipelines abandoned in place, treated wood poles for electric distribution, distribution transformers containing PCB (also known as Polychlorinated Biphenyl), and underground fuel storage tanks. The estimates of future liabilities were developed using historical information, and where available, quoted prices from outside contractors.

The increase of $13 million in the ARO from the revision of estimate in 2015 is primarily attributable to an increase in estimated disposal costs. The increase of $37 million in the ARO from the revision of estimate in 2014 is primarily attributable to a reduction of the estimated service lives of steel and plastic pipe.

(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.

CenterPoint Energy 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.

CenterPoint Energy 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 CenterPoint Energy's Consolidated Balance Sheets as of December 31, 2015 and 2014:

	December 31,	
	2015	2014
	(in millions)	
Securitized regulatory assets	$ 2,373	$ 2,738
Unrecognized equity return (1)	(393)	(442)
Unamortized loss on reacquired debt	93	104
Pension and postretirement-related regulatory asset (2)	872	922
Other long-term regulatory assets (3)	184	205
Total regulatory assets	3,129	3,527
Estimated removal costs	980	958
Other long-term regulatory liabilities	296	248
Total regulatory liabilities	1,276	1,206
Total regulatory assets and liabilities, net	$ 1,853	$ 2,321

(1) As of December 31, 2015, CenterPoint Energy has not recognized an allowed equity return of $393 million because such return will be recognized as it is recovered in rates through 2024. During the years ended

December 31, 2015, 2014 and 2013, CenterPoint Houston recognized approximately $49 million, $68 million and $45 million, respectively, of the allowed equity return. The timing of CenterPoint Energy's recognition of the allowed equity return will vary each period based on amounts actually collected during the period. The actual amounts recovered for the allowed equity return are reviewed and adjusted at least annually by the Texas Utility Commission to correct any over-collections or under-collections during the preceding 12 months and to provide for the full and timely recovery of the allowed equity return.

(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.

(3) Other regulatory assets that are not earning a return were not material as of December 31, 2015 and 2014.

(6) Stock-Based Incentive Compensation Plans and Employee Benefit Plans

(a) Stock-Based Incentive Compensation Plans

CenterPoint Energy has long-term incentive plans (LTIPs) that provide for the issuance of stock-based incentives, including stock options, performance awards, restricted stock unit awards and restricted and unrestricted stock awards to officers, employees and non-employee directors. Approximately 14 million shares of CenterPoint Energy common stock are authorized under these plans for awards.

Equity awards are granted to employees without cost to the participants. The performance awards granted in 2015, 2014 and 2013 are distributed based upon the achievement of certain objectives over a three-year performance cycle. The stock awards granted in 2015 and 2014 are service based. The stock awards granted in 2013 are subject to the performance condition that total common dividends declared during the three-year vesting period must be at least $2.49 per share. The stock awards generally vest at the end of a three-year period. Upon vesting, both the performance and stock awards are issued to the participants along with the value of dividend equivalents earned over the performance cycle or vesting period. CenterPoint Energy issues new shares in order to satisfy stock-based payments related to LTIPs.

CenterPoint Energy recorded LTIP compensation expense of $17 million, $18 million and $19 million for the years ended December 31, 2015, 2014 and 2013, respectively. This expense is included in Operation and Maintenance Expense in the Statements of Consolidated Income.

The total income tax benefit recognized related to LTIPs was $6 million, $7 million and $7 million for the years ended December 31, 2015, 2014 and 2013, respectively. No compensation cost related to LTIPs was capitalized as a part of inventory or fixed assets in 2015, 2014 or 2013. The actual tax benefit realized for tax deductions related to LTIPs totaled $6 million, $13 million and $13 million for 2015, 2014 and 2013, respectively.

Compensation costs for the performance and stock awards granted under LTIPs are measured using fair value and expected achievement levels on the grant date. For performance awards with operational goals, the achievement levels are revised as goals are evaluated. The fair value of awards granted to employees is based on the closing stock price of CenterPoint Energy’s common stock on the grant date. The compensation expense is recorded on a straight-line basis over the vesting period. Forfeitures are estimated on the date of grant based on historical averages, and estimates are updated periodically throughout the vesting period.

The following tables summarize CenterPoint Energy’s LTIP activity for 2015:

Stock Options

CenterPoint Energy has not issued stock options since 2004. There were no outstanding stock options at either December 31, 2015 or 2014.

Cash received from stock options exercised was $1 million and $3 million for 2014 and 2013, respectively.

Performance Awards

	Outstanding and Non-Vested Shares Year Ended December 31, 2015			
	Shares (Thousands)	Weighted-Average Grant Date Fair Value	Remaining Average Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of December 31, 2014	2,460	$ 21.26		
Granted	1,158	21.28		
Forfeited or canceled	(592)	19.89		
Vested and released to participants	(398)	18.79		
Outstanding as of December 31, 2015	2,628	21.95	1.2	$28

The outstanding and non-vested shares displayed in the table above assumes that shares are issued at the maximum performance level. The aggregate intrinsic value reflects the impact of current expectations of achievement and stock price.

Stock Awards

	Outstanding and Non-Vested Shares Year Ended December 31, 2015			
	Shares (Thousands)	Weighted-Average Grant Date Fair Value	Remaining Average Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of December 31, 2014	723	$ 21.41		
Granted	376	21.39		
Forfeited or canceled	(53)	22.40		
Vested and released to participants	(299)	20.08		
Outstanding as of December 31, 2015	747	21.86	1.1	$14

The weighted-average grant-date fair values per unit of awards granted were as follows for 2015, 2014 and 2013:

	Year Ended December 31,		
	2015	2014	2013
Performance awards	$21.28	$23.70	$20.67
Stock awards	21.39	23.89	21.53

Valuation Data

The total intrinsic value of awards received by participants was as follows for 2015, 2014 and 2013:

	Year Ended December 31,		
	2015	2014	2013
	(in millions)		
Stock options exercised	$—	$2	$4
Performance awards	9	24	20
Stock awards	7	10	10

The total grant date fair value of performance and stock awards which vested during the years ended December 31, 2015, 2014 and 2013 was $13 million, $21 million and $19 million, respectively. As of December 31, 2015, there was $18 million of total unrecognized compensation cost related to non-vested performance and stock awards which is expected to be recognized over a weighted-average period of 1.6 years.

(b) Pension and Postretirement Benefits

CenterPoint Energy maintains a non-contributory qualified defined benefit pension plan covering substantially all employees, with benefits determined using a cash balance formula. Under the cash balance formula, participants accumulate a retirement benefit based upon 5% of eligible earnings and accrued interest. Participants are 100% vested in their benefit after completing three years of service. In addition to the non-contributory qualified defined benefit pension plan, CenterPoint Energy maintains unfunded 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.

CenterPoint Energy provides 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. The net unrecognized transition obligation is being amortized over approximately 20 years.

CenterPoint Energy's net periodic cost includes the following components relating to pension, including the benefit restoration plan, and postretirement benefits:

	Year Ended December 31,					
	2015		2014		2013	
	Pension Benefits	Post-retirement Benefits	Pension Benefits	Post-retirement Benefits	Pension Benefits	Post-retirement Benefits
	(in millions)					
Service cost	$41	$ 2	$42	$ 2	$44	$ 2
Interest cost	93	20	100	22	90	20
Expected return on plan assets	(120)	(7)	(125)	(7)	(135)	(7)
Amortization of prior service cost (credit)	9	(1)	10	(1)	10	1
Amortization of net loss	57	5	44	1	63	6
Amortization of transition obligation	—	—	—	5	—	7
Curtailment (1)	—	—	6	—	—	—
Settlement (2)	10	—	—	—	—	—
Net periodic cost	$90	$ 19	$77	$ 22	$72	$ 29

(1) During the fourth quarter of 2014, CenterPoint Energy recognized a curtailment pension loss of $6 million related to employees seconded to Enable. Substantially all of the seconded employees became employees of Enable effective January 1, 2015.

(2) A one-time, non-cash settlement charge is required when lump sum distributions or other settlements of plan benefit obligations during a plan year exceed the service cost and interest cost components of net periodic cost for that year. Due to the amount of lump sum payment distributions from the non-qualified pension plan during the year ended December 31, 2015, CenterPoint Energy recognized a non-cash settlement charge of $10 million. This charge is an acceleration of costs that would otherwise be recognized in future periods.

CenterPoint Energy used the following assumptions to determine net periodic cost relating to pension and postretirement benefits:

	Year Ended December 31,					
	2015		2014		2013	
	Pension Benefits	Post-retirement Benefits	Pension Benefits	Post-retirement Benefits	Pension Benefits	Post-retirement Benefits

Discount rate	4.05 %	3.90 %	4.80 %	4.75 %	4.00 %	3.90 %
Expected return on plan assets	6.50	5.20	7.00	5.50	8.00	5.50
Rate of increase in compensation levels	4.00	—	3.90	—	4.00	—

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

The following table summarizes changes in the benefit obligation, plan assets, the amounts recognized in consolidated balance sheets and the key assumptions of CenterPoint Energy's pension, including benefit restoration, and postretirement plans. The measurement dates for plan assets and obligations were December 31, 2015 and 2014.

	December 31,			
	2015		2014	
	Pension Benefits	Post-retirement Benefits	Pension Benefits	Post-retirement Benefits
	(in millions, except for actuarial assumptions)			
Change in Benefit Obligation				
Benefit obligation, beginning of year	$2,403	$ 529	$2,153	$ 476
Service cost	41	2	42	2
Interest cost	93	20	100	22
Participant contributions	—	8	—	7
Benefits paid	(234)	(32)	(156)	(32)
Actuarial (gain) loss	(115)	(87)	264	52
Medicare reimbursement	—	2	—	3
Plan amendment	—	(10)	—	1
Settlement	5	—	—	—
Curtailment	—	—	—	(2)
Benefit obligation, end of year	2,193	432	2,403	529
Change in Plan Assets				
Fair value of plan assets, beginning of year	1,925	141	1,803	140
Employer contributions	66	18	97	18
Participant contributions	—	8	—	7
Benefits paid	(234)	(32)	(156)	(32)
Actual investment return (loss)	(78)	1	181	8
Fair value of plan assets, end of year	1,679	136	1,925	141
Funded status, end of year	$(514)	$ (296)	$(478)	$ (388)
Amounts Recognized in Balance Sheets				
Current liabilities-other	$(8)	$ (8)	$(31)	$ (9)
Other liabilities-benefit obligations	(506)	(288)	(447)	(379)
Net liability, end of year	$(514)	$ (296)	$(478)	$ (388)
Actuarial Assumptions				
Discount rate	4.40 %	4.35 %	4.05 %	3.90 %
Expected return on plan assets	6.25	4.80	6.50	5.20
Rate of increase in compensation levels	4.15	—	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 drug cost trend rate assumed for the next year	—	11.00	—	6.50
Rate to which the cost trend rate is assumed to decline (the 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 accumulated benefit obligation for all defined benefit pension plans was $2,157 million and $2,371 million as of December 31, 2015 and 2014, respectively.

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.

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.

For measurement purposes, medical costs are assumed to increase 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.

CenterPoint Energy's changes in accumulated comprehensive loss related to defined benefit, postretirement and other postemployment plans are as follows:

	Year Ended December 31,	
	2015	2014
	(in millions)	
Beginning Balance	$(85)	$(88)
Other comprehensive income (loss) before reclassifications (1)	21	(3)
Amounts reclassified from accumulated other comprehensive income:		
Prior service cost (2)	1	2
Actuarial losses (2)	10	9
Total reclassifications from accumulated other comprehensive income	11	11
Tax expense	(12)	(5)
Net current period other comprehensive income	20	3
Ending Balance	$(65)	$(85)

(1) Total other comprehensive income (loss) 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 loss consist of the following:

	December 31,			
	2015		2014	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(in millions)			
Unrecognized actuarial loss (gain)	$106	$(2)	$113	$14
Unrecognized prior service cost (credit)	3	(1)	4	2
Net amount recognized in accumulated other comprehensive loss	$109	$(3)	$117	$16

The changes in plan assets and benefit obligations recognized in other comprehensive income during 2015 are as follows:

	Pension Benefits	Postretirement Benefits
	(in millions)	
Net gain	$—	$18
Amortization of net loss	7	1
Amortization of prior service credit	1	—
Total recognized in comprehensive income	$8	$19

The total expense recognized in net periodic costs and other comprehensive income was $82 million and $-0- for pension and postretirement benefits, respectively, for the year ended December 31, 2015.

The amounts in accumulated other comprehensive loss expected to be recognized as components of net periodic benefit cost during 2016 are as follows:

	Pension Benefits	Postretirement Benefits
	(in millions)	
Unrecognized actuarial loss	$7	$—
Unrecognized prior service cost	1	—
Amounts in accumulated comprehensive loss to be recognized in net periodic cost in 2016	$8	$—

The following table displays pension benefits related to CenterPoint Energy's pension plans that have accumulated benefit obligations in excess of plan assets:

	December 31, 2015		2014	
	Pension Qualified	Pension Non-qualified	Pension Qualified	Pension Non-qualified
	(in millions)			
Accumulated benefit obligation	$2,082	$75	$2,273	$98
Projected benefit obligation	2,118	75	2,304	98
Fair value of plan assets	1,679	—	1,925	—

Assumed healthcare cost trend rates have a significant effect on the reported amounts for CenterPoint Energy'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	$12	$10
Effect on total of service and interest cost	1	1

In managing the investments associated with the benefit plans, CenterPoint Energy's objective is to achieve and maintain a fully funded plan. This objective is 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, CenterPoint Energy maintained the following weighted average allocation targets for its benefit plans as of December 31, 2015:

	Pension Benefits	Postretirement Benefits
U.S. equity	12 – 28%	14 – 24%
International developed market equity	7 – 17%	3 – 13%
Emerging market equity	3 – 13%	—
Fixed income	54 – 66%	68 – 78%
Cash	0 – 2%	0 – 2%

The following tables set forth by level, within the fair value hierarchy (see Note 8), CenterPoint Energy's pension plan assets at fair value as of December 31, 2015 and 2014:

	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)			
Cash	$11	$11	$—	$—
Common collective trust funds (1)	896	—	896	—
Corporate bonds:				
Investment grade or above	385	—	385	—
Equity securities:				
International companies	38	38	—	—
U.S. companies	74	74	—	—
Cash received as collateral from securities lending	71	71	—	—
U.S. treasuries	57	57	—	—
Mortgage backed securities	4	—	4	—
Asset backed securities	3	—	3	—
Municipal bonds	66	—	66	—
Mutual funds (2)	144	144	—	—
International government bonds	1	—	1	—
Obligation to return cash received as collateral from securities lending	(71)	(71)	—	—
Total	$1,679	$324	$1,355	$—

(1) 60% of the amount invested in common collective trust funds was in fixed income securities, 11% was in U.S. equities, 23% was in international equities and 2% was in emerging market equities.

(2) 58% of the amount invested in mutual funds was in international equities, 28% was in emerging market equities and 14% was in U.S. equities.

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	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)			
Cash	$6	$6	$—	$—
Common collective trust funds (1)	1,108	—	1,108	—
Corporate bonds:				
Investment grade or above	368	—	368	—
Equity securities:				
International companies	49	49	—	—
U.S. companies	83	83	—	—
Cash received as collateral from securities lending	86	86	—	—
U.S. treasuries	47	47	—	—
Mortgage backed securities	4	—	4	—
Asset backed securities	4	—	4	—
Municipal bonds	79	—	79	—
Mutual funds (2)	161	161	—	—
International government bonds	15	—	15	—
Real estate	1	—	—	1
Obligation to return cash received as collateral from securities lending	(86)	(86)	—	—
Total	$1,925	$346	$1,578	$1

(1) 61% of the amount invested in common collective trust funds was in fixed income securities, 14% was in U.S. equities, 22% was in international equities and 3% was in emerging market equities.

(2) 57% of the amount invested in mutual funds was in international equities, 30% was in emerging market equities and 13% was in U.S. equities.

The pension plan utilized both exchange traded and over-the-counter financial instruments such as futures, interest rate options and swaps that were marked to market daily with the gains/losses settled in the cash accounts. The pension plan did not include any holdings of CenterPoint Energy common stock as of December 31, 2015 or 2014.

The changes in the fair value of the pension plan's level 3 investments for the years ended December 31, 2015 and 2014 were not material.

The following tables present by level, within the fair value hierarchy, CenterPoint Energy's postretirement plan assets at fair value as of December 31, 2015 and 2014, by asset category:

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

		(Level 1)		
	(in millions)			
Mutual funds (1)	$136	$136	$—	$—
Total	$136	$136	$—	$—

(1) 72% of the amount invested in mutual funds was in fixed income securities, 20% was in U.S. equities and 8% 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)	$141	$141	$—	$—
Total	$141	$141	$—	$—

(1) 73% of the amount invested in mutual funds was in fixed income securities, 19% was in U.S. equities and 8% was in international equities.

CenterPoint Energy contributed $35 million, $31 million and $18 million to its qualified pension, non-qualified pension and postretirement benefits plans, respectively, in 2015. CenterPoint Energy expects to contribute approximately $-0-, $8 million and $16 million to its qualified pension, non-qualified pension and postretirement benefits plans, respectively, in 2016.

The following benefit payments are expected to be paid by the pension and postretirement benefit plans:

		Postretirement Benefit Plan	
	Pension Benefits	Benefit Payments	Medicare Subsidy Receipts
	(in millions)		
2016	$139	$32	$(4)
2017	144	34	(4)
2018	155	35	(5)
2019	157	37	(6)
2020	163	38	(6)
2021-2025	822	203	(41)

(c) Savings Plan

CenterPoint Energy has a tax-qualified employee savings plan that includes a cash or deferred arrangement under Section 401(k) of the Internal Revenue Code of 1986, as amended (the Code), and an employee stock ownership plan (ESOP) under Section 4975(e)(7) of the Code. 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. The Company 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's savings plan benefit expenses were $35 million, $39 million and $38 million in 2015, 2014 and 2013, respectively.

(d) Postemployment Benefits

CenterPoint Energy provides postemployment benefits for certain former or inactive employees, their beneficiaries and covered dependents, after employment but before retirement (primarily healthcare and life insurance benefits for participants in the long-term disability plan). CenterPoint Energy recorded postemployment expenses of $2 million, $3 million and $4 million in 2015, 2014 and 2013, respectively.

Included in Benefit Obligations in the accompanying Consolidated Balance Sheets as of December 31, 2015 and 2014 was $23 million and $28 million, respectively, relating to postemployment obligations.

(e) Other Non-Qualified Plans

CenterPoint Energy has non-qualified 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 CenterPoint Energy. CenterPoint Energy recorded benefit expense relating to these plans of $3 million, $5 million and $5 million for the years in 2015, 2014 and 2013, respectively. Included in Benefit Obligations in the accompanying Consolidated Balance Sheets as of December 31, 2015 and 2014 was $51 million and $60 million, respectively, relating to deferred compensation plans.

Included in Benefit Obligations in CenterPoint Energy's Consolidated Balance Sheets as of December 31, 2015 and 2014 was $32 million and $33 million, respectively, relating to split-dollar life insurance arrangements.

(f) Change in Control Agreements and Other Employee Matters

CenterPoint Energy had change in control agreements with certain of its officers, which expired December 31, 2014. In lieu of these agreements, our Board of Directors approved a new change in control plan, which was effective January 1, 2015. The plan, like the expired agreements, generally provides, to the extent applicable, in the case of a change in control of CenterPoint Energy and termination of employment, for severance benefits of up to three times annual base salary plus bonus, and other benefits. Our officers, including our Executive Chairman, are participants under the plan.

As of December 31, 2015, approximately 35% of CenterPoint Energy's employees were subject to collective bargaining agreements. The collective bargaining agreement with the International Brotherhood of Electrical Workers Local 66 and the two collective bargaining agreements with Professional Employees International Union Local 12, which collectively cover approximately 21% 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.

(7) Derivative Instruments

CenterPoint Energy is exposed to various market risks. These risks arise from transactions entered into in the normal course of business. CenterPoint Energy 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. CenterPoint Energy 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. CenterPoint Energy has weather normalization or other rate mechanisms that mitigate the impact of weather on NGD in Arkansas, Louisiana, Mississippi, Minnesota and Oklahoma. NGD and electric operations in Texas do not have such mechanisms, although fixed customer charges are historically higher in Texas for NGD compared to CenterPoint Energy’s other jurisdictions. As a result, fluctuations from normal weather may have a positive or negative effect on NGD’s results in Texas and on CenterPoint Houston’s results in its service territory.

CenterPoint Energy 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. CenterPoint Energy also entered into weather hedges for the CenterPoint Houston service territory, which contained a bilateral dollar cap of $8 million for both the 2013–2014 and 2014–2015 winter seasons and a bilateral dollar cap of $7 million for the 2015–2016 winter season. The swaps are based on 10-year normal weather. During the years ended December 31, 2015, 2014 and 2013, CenterPoint Energy recognized losses of $6 million, $11 million and $22 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 CenterPoint Energy's derivative instruments and hedging activities. The first four tables provide a balance sheet overview of CenterPoint Energy'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 (in millions)	Derivative Liabilities Fair Value
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
Indexed debt securities derivative	Current Liabilities	—	442
Total		$140	$529

(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 CenterPoint Energy'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	Gross Amounts Offset in the Consolidated	Net Amount Presented in the

	(1)	Balance Sheets	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

	December 31, 2014		
Total derivatives not designated as hedging instruments	Balance Sheet Location	Derivative Assets Fair Value (in millions)	Derivative Liabilities Fair Value
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
Indexed debt securities derivative	Current Liabilities	—	541
Total		$149	$643

(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 CenterPoint Energy'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

	December 31, 2014		
	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	$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 CenterPoint Energy’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. Unrealized gains and losses on indexed debt securities are recorded as Other Income (Expense) in the Statements of Consolidated Income.

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 in Revenue	$134	$35	$11
Natural gas derivatives (1)	Gains (Losses) in Expense: Natural Gas	(105)	11	10
Indexed debt securities derivative	Gains (Losses) in Other Income (Expense)	74	(86)	(193)
Total		$103	$(40)	$(172)

(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

CenterPoint Energy enters into financial derivative contracts containing material adverse change provisions. These provisions could require CenterPoint Energy to post additional collateral if the Standard & Poor's Ratings Services or Moody's Investors Service, Inc. credit ratings of CenterPoint Energy, Inc. or its subsidiaries 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. CenterPoint Energy 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 CenterPoint Energy'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 CenterPoint Energy 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
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, CenterPoint Energy 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.

(8) 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 CenterPoint Energy'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 CenterPoint Energy's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. CenterPoint Energy develops these inputs based on the best information available, including CenterPoint Energy's own data. A market approach is utilized to value CenterPoint Energy's Level 3 assets or liabilities. At December 31, 2015, CenterPoint Energy'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. CenterPoint Energy'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, CenterPoint Energy's long forwards lose value whereas its short forwards gain in value. If volatility decreases, CenterPoint Energy's long options lose value whereas its short options gain in value.

CenterPoint Energy 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. CenterPoint Energy 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 CenterPoint Energy'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 CenterPoint Energy to determine such fair value.

	Quoted Prices in Active Markets for Identical Assets (Level 1) (in millions)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Adjustments (1)	Balance as of December 31, 2015
Assets					
Corporate equities	$807	$—	$—	$—	$807
Investments, including money market funds	53	—	—	—	53
Natural gas derivatives (2)	4	115	21	(15)	125
Total assets	$864	$115	$21	$(15)	$985
Liabilities					
Indexed debt securities derivative	$—	$442	$—	$—	$442
Natural gas derivatives (2)	13	65	9	(71)	16
Total liabilities	$13	$507	$9	$(71)	$458

(1) Amounts represent the impact of legally enforceable master netting arrangements that allow CenterPoint Energy 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) (in millions)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Adjustments [1]	Balance as of December 31, 2014
Assets					
Corporate equities	$932	$—	$—	$—	$932
Investments, including money market funds	54	—	—	—	54
Natural gas derivatives (2)	7	122	20	(18)	131
Total assets	$993	$122	$20	$(18)	$1,117
Liabilities					
Indexed debt securities derivative	$—	$541	$—	$—	$541
Natural gas derivatives	22	77	3	(82)	20
Total liabilities	$22	$618	$3	$(82)	$561

(1) Amounts represent the impact of legally enforceable master netting arrangements that allow CenterPoint Energy 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 CenterPoint Energy 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 (in millions)	2014	2013
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. CenterPoint Energy based its assumptions on projected financial information that CenterPoint Energy 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, CenterPoint Energy 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 9 for further discussion of the impairments. 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, investments in debt and equity securities classified as “trading” and short-term borrowings are estimated to be approximately equivalent to carrying amounts and have been excluded from the table below. The carrying amounts of non-trading derivative assets and liabilities and CenterPoint Energy’s 2.0% Zero-Premium Exchangeable Subordinated Notes due 2029 (ZENS) indexed debt securities derivative are stated at fair value and are excluded from the table below. The fair value of each debt instrument is determined by multiplying the principal amount of each debt instrument by the market price. These assets and liabilities, which are not measured at fair value in the Consolidated Balance Sheets but for which the fair value is disclosed, would be classified as Level 1 or Level 2 in the fair value hierarchy.

	December 31, 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	$8,620	$9,101	$8,652	$9,427

(9) 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 CenterPoint Energy 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.

CenterPoint Energy's maximum exposure to loss related to Enable, a VIE in which CenterPoint Energy 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 14, 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 18. CenterPoint Energy 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, CenterPoint Energy 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. CenterPoint Energy expects to provide certain services to Enable following the completion of the initial term.

CenterPoint Energy 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 CenterPoint Energy. During the fourth quarter of 2014, Enable notified CenterPoint Energy that it selected seconded employees and provided employment offers to substantially all of the seconded employees from CenterPoint Energy. 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 CenterPoint Energy's common units were converted into subordinated units, as discussed further below. Subsequent to the IPO, Enable continues to be controlled jointly by CenterPoint Energy and OGE.

As a result of Enable's IPO, CenterPoint Energy's limited partner interest in Enable was reduced from approximately 58.3% to approximately 54.7%. CenterPoint Energy 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. CenterPoint Energy did not receive any cash from Enable's IPO and, as such, CenterPoint Energy did not recognize a gain or loss. CenterPoint Energy's basis difference in Enable was reduced for the impact of the Enable IPO.

In accordance with the Enable formation agreements, CenterPoint Energy 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 CenterPoint Energy on the Closing Date, under which CenterPoint Energy 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 CenterPoint Energy to Enable or from Enable to CenterPoint Energy, 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.

CenterPoint Energy 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.

CenterPoint Energy 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.

CenterPoint Energy 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. CenterPoint Energy 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, CenterPoint Energy 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, CenterPoint Energy 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.

CenterPoint Energy 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 CenterPoint Energy's impairment of its investment in Enable of $1,225 million and CenterPoint Energy's share, $621 million, of impairment charges Enable recorded for goodwill and long-lived assets.

CenterPoint Energy 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, CenterPoint Energy 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. CenterPoint Energy 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 CenterPoint Energy's total investment in Enable, which includes the limited partner common and subordinated units, general partner interest and incentive distribution rights held by CenterPoint Energy. 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 8 for further discussion of the determination of fair value of CenterPoint Energy'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) CenterPoint Energy 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) CenterPoint Energy 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:			
CenterPoint Energy's interest	$(416)	$298	$168
Basis difference amortization (1)	8	5	5
Impairment of CenterPoint Energy's equity method investment in Enable	(1,225)	—	—
CenterPoint Energy's equity in earnings (losses), net (2)	$(1,633)	$303	$173

(1) Equity in earnings of unconsolidated affiliates includes CenterPoint Energy's share of Enable earnings adjusted for the amortization of the basis difference of CenterPoint Energy'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 CenterPoint Energy's share of Enable's impairment of goodwill and long-lived assets and the impairment of CenterPoint Energy'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:		
CenterPoint Energy's ownership interest in Enable partners' capital	$4,163	$4,869
CenterPoint Energy's basis difference	(1,569)	(349)
CenterPoint Energy'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) CenterPoint Energy 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.

(10) Indexed Debt Securities (ZENS) and Securities Related to ZENS

(a) Investment in Securities Related to ZENS

In 1995, CenterPoint Energy sold a cable television subsidiary to Time Warner, Inc. (TW) and received TW securities as partial consideration. A subsidiary of CenterPoint Energy now holds 7.1 million shares of TW common stock (TW Common), 1.8 million shares of Time Warner Cable Inc. (TWC) common stock (TWC Common) and 0.9 million shares of Time Inc. common stock (Time Common) (together with the TW Common and TWC Common, the TW Securities) which are classified as trading securities and are expected to be held to facilitate CenterPoint Energy’s ability to meet its obligation under the ZENS. Unrealized gains and losses resulting from changes in the market value of the TW Securities are recorded in CenterPoint Energy’s Statements of Consolidated Income.

(b) ZENS

In September 1999, CenterPoint Energy issued ZENS having an original principal amount of $1 billion of which $828 million remain outstanding at December 31, 2015. Each ZENS note was originally exchangeable at the holder’s option at any time for an amount of cash equal to 95% of the market value of the reference shares of TW Common attributable to such note. The number and identity of the reference shares attributable to each ZENS note are adjusted for certain corporate events. Prior to the closing of the merger discussed below, the reference shares for each ZENS note consisted of 0.5 share of TW Common, 0.125505 share of TWC Common, 0.045455 share of AOL Inc. common stock (AOL Common) and 0.0625 share of Time Common.

On May 26, 2015, Verizon Communications, Inc. (Verizon) initiated a tender offer to purchase all outstanding shares of AOL Common for $50 per share, in which CenterPoint Energy tendered all of its shares of AOL Common for $32 million. Verizon acquired the remaining eligible shares through a merger, which closed on June 23, 2015. In accordance with the terms of the ZENS, CenterPoint Energy remitted $32 million to ZENS holders in July 2015, which reduced contingent principal. As a result, CenterPoint Energy recorded a reduction in the indexed debt securities derivative liability of $18 million, a reduction in the indexed debt balance of $7 million and a loss of $7 million, which is included in Gain (loss) on indexed debt securities on the Statements of Consolidated Income. As of December 31, 2015, the reference shares for each ZENS note consisted of 0.5 share of TW Common, 0.125505 share of TWC Common and 0.0625 share of Time Common.

On May 26, 2015, Charter Communications, Inc. (Charter) announced that it had entered into a definitive merger agreement with TWC. On September 21, 2015, Charter shareholders approved the announced transaction with TWC. Pursuant to the merger agreement, upon closing of the merger, TWC Common shares would be exchanged for cash and Charter stock and as a result, reference shares would consist of Charter stock, TW Common and Time Common. The merger is expected to close by June of 2016.

CenterPoint Energy pays interest on the ZENS at an annual rate of 2% plus the amount of any quarterly cash dividends paid in respect of the reference shares attributable to the ZENS. The principal amount of ZENS is subject to being increased or decreased to the extent that the annual yield from interest and cash dividends on the reference shares is less than or more than 2.309%. The adjusted principal amount is defined in the ZENS instrument as "contingent principal." At December 31, 2015, ZENS having an original principal amount of $828 million and a contingent principal amount of $705 million were outstanding and were exchangeable, at the option of the holders, for cash equal to 95% of the market value of reference shares deemed to be attributable to the ZENS. As of December 31, 2015, the market value of such shares was approximately $805 million, which would provide an exchange amount of $923 for each $1,000 original principal amount of ZENS. At maturity of the ZENS in 2029, CenterPoint Energy will be obligated to pay in cash the higher of the contingent principal amount of the ZENS or an amount based on the then-current market value of the reference shares, which will include any additional publicly-traded securities distributed with respect to the current reference shares prior to maturity.

The ZENS obligation is bifurcated into a debt component and a derivative component (the holder's option to receive the appreciated value of the reference shares at maturity). The bifurcated debt component accretes through interest charges at 17.4% annually up to the contingent principal amount of the ZENS in 2029. Such accretion will be reduced by annual cash interest payments, as described above. The derivative component is recorded at fair value and changes in the fair value of the derivative component are recorded in CenterPoint Energy's Statements of Consolidated Income. Changes in the fair value of the TW Securities held by CenterPoint Energy are expected to substantially offset changes in the fair value of the derivative component of the ZENS.

The following table sets forth summarized financial information regarding CenterPoint Energy's investment in TW Securities and each component of CenterPoint Energy's ZENS obligation.

	TW Securities	Debt Component of ZENS	Derivative Component of ZENS
	(in millions)		
Balance as of December 31, 2012	$540	$138	$268
Accretion of debt component of ZENS	—	24	—
2% interest paid	—	(17)	—
Sale of TW Securities	(9)	—	—
Redemption of indexed debt securities	—		