

CENTERPOINT ENERGY INC
Form 10-K
February 26, 2014

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

Form 10-K
(Mark One)

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

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2013

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

FOR THE TRANSITION PERIOD FROM TO

Commission File Number 1-31447

CenterPoint Energy, Inc.
(Exact name of registrant as specified in its charter)
Texas
(State or other jurisdiction of incorporation or organization)

74-0694415
(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
New York Stock Exchange
Chicago Stock Exchange

Common Stock, \$0.01 par value

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 No

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

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to

submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer Accelerated filer Non-accelerated filer Smaller reporting company
(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 No

The aggregate market value of the voting stock held by non-affiliates of CenterPoint Energy, Inc. (CenterPoint Energy) was \$9,975,930,939 as of June 30, 2013, 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 14, 2014, CenterPoint Energy had 428,841,792 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 2014 Annual Meeting of Shareholders of CenterPoint Energy, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2013, 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 a 5,000-square mile area of the Texas Gulf Coast 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 in six states (Gas Operations). 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, 2013, CERC Corp. also owned approximately 58.3% of the limited partner interests in Enable, an unconsolidated partnership jointly controlled with OGE Energy Corp., 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. 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, finance 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. 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 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 85% 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 74,000 megawatts (MW) at December 31, 2013. 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). These reliability standards are administered by the Texas Regional Entity (TRE), a functionally independent division of ERCOT. 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. Unlike certain other regional power markets, the ERCOT market is not a centrally dispatched power pool, and the ERCOT ISO does not procure energy on behalf of its members other than to maintain the reliable operations of the transmission system. Members who sell and purchase power are responsible for contracting sales and purchases of power bilaterally. The ERCOT ISO also serves as agent for procuring ancillary services for those members who elect not to provide their own ancillary services.

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, 2013, approximately \$2.9 billion aggregate principal amount of transition bonds were outstanding.

Customers

CenterPoint Houston serves nearly all of the Houston/Galveston metropolitan area. At December 31, 2013, CenterPoint Houston's customers consisted of approximately 70 REPs, which sell electricity to over two 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 38%, 39% and 36% of CenterPoint Houston's transmission and distribution revenues in 2013, 2012 and 2011, respectively. Sales to REPs that are affiliates of Energy Future Holdings Corp. (Energy Future Holdings) represented approximately 10%, 10% and 11% of CenterPoint Houston's transmission and distribution revenues in 2013, 2012 and 2011, respectively. CenterPoint Houston's aggregate billed receivables balance from REPs as of December 31, 2013 was \$172 million. Approximately 38%, 8% and 8% of this amount was owed by affiliates of NRG, Just Energy Group, Inc. 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. This technology should encourage greater energy conservation by giving Houston-area electric consumers the ability to better monitor and manage their electric use and its cost in near real time. To recover the cost of the AMS, the Texas Utility Commission approved a monthly surcharge payable by REPs, initially over 12 years. For the first 24 months, which began in February 2009, the surcharge for residential customers was \$3.24 per month. Beginning in February 2011, the surcharge was reduced to \$3.05 per month. In September 2011, the surcharge duration was reduced from 12 years to approximately six years for residential customers and approximately eight years for commercial 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. Please read “ – Management’s Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Regulatory Matters – CenterPoint Houston.”

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. Although this technology is still in the developmental stage, CenterPoint Houston believes it has the potential to provide an improvement in grid planning, operations, maintenance and customer service for the CenterPoint Houston distribution system. These improvements are expected to result in fewer and shorter outages, better customer service, improved operations costs, improved security and more effective use of our workforce. We expect to include the costs of the deployment in future rate proceedings before the Texas Utility Commission.

In October 2009, the U.S. Department of Energy (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, instead of 2014 as originally scheduled. CenterPoint Houston estimates that capital expenditures of approximately \$660 million for the installation of the advanced meters and corresponding communication and data management systems were incurred over the advanced meter deployment period. CenterPoint Houston is using the other \$50 million from the grant for an initial deployment of an IG that covers approximately 12% of its service territory. This initial deployment is expected to be completed in 2014. It is expected that the capital portion of the IG

project subject to partial funding by the DOE will 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 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, 2013, CenterPoint Houston had approximately \$1.9 billion aggregate principal amount of general mortgage bonds outstanding under the General Mortgage, including (a) \$290 million held in trust to secure pollution control bonds that are not reflected in our consolidated financial statements because we are both the obligor on the bonds and the current owner of the bonds, (b) approximately \$118 million held in trust to secure pollution control bonds for which we are obligated and (c) approximately \$183 million held in trust to secure pollution control bonds for which CenterPoint Houston is obligated. Additionally, as of December 31, 2013, 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 \$3.9 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, 2013. 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, 2013, CenterPoint Houston owned 28,113 pole miles of overhead distribution lines and 3,703 circuit miles of overhead transmission lines, including 355 circuit miles operated at 69,000 volts, 2,132 circuit miles operated at 138,000 volts and 1,216 circuit miles operated at 345,000 volts.

Electric Lines - Underground. As of December 31, 2013, CenterPoint Houston owned 21,763 circuit miles of underground distribution lines and 26 circuit miles of underground transmission lines, including 2 circuit miles operated at 69,000 volts and 24 circuit miles operated at 138,000 volts.

Substations. As of December 31, 2013, CenterPoint Houston owned 234 major substation sites having a total installed rated transformer capacity of 54,931 megavolt amperes.

Service Centers. CenterPoint Houston operates 14 regional service centers located on a total of 291 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 natural gas distribution business (Gas Operations) engages in regulated intrastate natural gas sales to, and natural gas transportation for, approximately 3.3 million residential, commercial and industrial customers in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma and Texas. The largest metropolitan areas served in each state by Gas Operations are Houston, Texas; Minneapolis, Minnesota; Little Rock, Arkansas; Shreveport, Louisiana; Biloxi, Mississippi; and Lawton, Oklahoma. In 2013, approximately 41% of Gas Operations' total throughput was to residential customers and approximately 59% was to commercial and industrial customers.

The table below reflects the number of natural gas distribution customers by state as of December 31, 2013:

	Residential	Commercial/ Industrial	Total Customers
Arkansas	383,454	48,323	431,777
Louisiana	231,508	17,182	248,690
Minnesota	754,575	68,498	823,073
Mississippi	111,016	12,585	123,601
Oklahoma	91,582	10,798	102,380
Texas	1,518,831	89,714	1,608,545
Total Gas Operations	3,090,966	247,100	3,338,066

Gas Operations also provides unregulated services in Minnesota consisting of residential appliance repair and maintenance services along with heating, ventilating and air conditioning (HVAC) equipment sales.

The demand for intrastate natural gas sales to residential customers and natural gas sales and transportation for commercial and industrial customers is seasonal. In 2013, approximately 68% of the total throughput of Gas Operations' business occurred in the first and fourth quarters. These patterns reflect the higher demand for natural gas for heating purposes during those periods.

Supply and Transportation. In 2013, Gas Operations 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 2013 included BP Energy Company/BP Canada Energy Marketing (16.2% of supply volumes), Cargill, Inc. (13.2%), Tenaska Marketing Ventures (10.5%), Kinder Morgan Tejas Pipeline/Kinder Morgan Texas Pipeline (8.1%), Shell Energy North America (7.8%), Sequent Energy Management (4.5%), Conoco Inc. (4.0%), Mico Inc. (3.4%), Renaissance (2.7%), and Laclede Energy Resources (2.5%). Numerous other suppliers provided the remaining 27.1% of Gas Operations' natural gas supply requirements. Gas Operations transports its natural gas supplies through various intrastate and interstate pipelines, including those owned by our other subsidiaries, under contracts with remaining terms, including extensions, varying from one to ten years. Gas Operations anticipates that these gas supply and transportation contracts will be renewed or replaced prior to their expiration.

Gas Operations 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 Gas Operations 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.

Gas Operations 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.

Gas Operations 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

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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, Gas Operations 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.

Gas Operations has entered into various asset management agreements associated with its utility distribution service in Arkansas, Louisiana, Mississippi, Oklahoma and Texas. Generally, these asset management agreements are contracts between Gas Operations and an asset manager that are intended to transfer the working capital obligation and maximize the utilization of the assets. In these agreements, Gas Operations agreed to release transportation and storage capacity to other parties to manage gas storage, supply and delivery arrangements for Gas Operations and to use the released capacity for other purposes when it is not needed for Gas Operations. Gas Operations 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. Gas Operations has received approval from the state regulatory commissions in Arkansas, Louisiana, Mississippi and Oklahoma to retain a share of the asset management agreement proceeds. The agreements have varying terms, the longest of which expires in 2016.

Assets

As of December 31, 2013, Gas Operations owned approximately 73,000 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 Gas Operations, 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 Gas Operations 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

Gas Operations 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 Gas Operations' 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 2013, CES marketed approximately 600 Bcf of natural gas, related energy services and transportation to approximately 17,500 customers (including approximately 6 Bcf to affiliates) in 21 states. Not included in the 2013 customer count are approximately 8,800 natural gas customers that are served under residential and small commercial choice programs invoiced by their host utility. CES customers vary in size from small commercial customers to large utility companies in the central and eastern regions of the United States.

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 and financial products 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 currently transports natural gas on 47 interstate and intrastate pipelines within states located throughout the central and eastern United States. 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, 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. The CES business 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, 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 2013, CES' VaR averaged \$0.2 million with a high of \$0.7 million.

Assets

CEIP owns and operates approximately 235 miles of intrastate pipeline in Louisiana and Texas and contracts out approximately 2.3 Bcf of storage at its Pierce Junction facility in Texas under long-term leases. 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

On March 14, 2013, CenterPoint Energy entered into a Master Formation Agreement (MFA) with OGE Energy Corp. (OGE) and affiliates of ArcLight Capital Partners, LLC (ArcLight), pursuant to which CenterPoint Energy, OGE and ArcLight agreed to form Enable as a private limited partnership. On May 1, 2013, the parties closed on the formation of Enable pursuant to which Enable became the owner of substantially all of CERC Corp.'s former Interstate Pipelines and Field Services businesses.

As of December 31, 2013, CERC Corp., OGE and ArcLight held approximately 58.3%, 28.5% and 13.2%, respectively, of the limited partner interests in Enable. Enable is equally controlled by CERC Corp. and OGE; each own 50% of the management rights in the general partner of Enable. CERC Corp. and OGE also own a 40% and 60% interest, respectively, in the incentive distribution rights held by the general partner of Enable.

Our investment in Enable is accounted for on an equity basis. Equity earnings associated with CenterPoint Energy's interest in Enable and equity earnings associated with CenterPoint Energy's 25.05% interest in Southeast Supply Header, LLC (SESH) are reported under the Midstream Investments segment.

Enable. Enable's assets and operations are organized into two business 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 service to natural gas producers, utilities and industrial customers.

Enable's natural gas gathering and processing assets are located in four states and serve natural gas production from shale developments in the Anadarko, Arkoma and Ark-La-Tex basins. Enable also owns an emerging crude oil gathering business in the Bakken shale formation that commenced initial operations in November 2013. 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, 2013, Enable's assets included approximately 11,000 miles of gathering pipelines, 12 major processing plants with approximately 2.1 Bcf/d of processing capacity, approximately 7,900 miles of interstate pipelines (including SESH), approximately 2,300 miles of intrastate pipelines and eight storage facilities comprising 86.5 Bcf of storage capacity.

Enable's Gathering and Processing segment. Enable provides gathering, processing, treating, compression, dehydration and natural gas liquids (NGL) fractionation for natural gas producers. Six of Enable's processing plants in the Anadarko basin are interconnected via its large-diameter, rich gas gathering system in western Oklahoma, which spans 18 counties and has approximately 1.2 Bcf/d of processing capacity. Enable refers to this system as its "super-header" system. Enable has configured this system to optimize the flow of natural gas and the utilization of the processing plants connected to it. Enable has made investments to expand the super-header system, including its newest plant located in Custer County, Oklahoma (the McClure Plant) that was placed in service in December 2013. The McClure Plant increased Enable's natural gas processing capacity in the basin by over 15%, providing an additional 200 MMcf/d of natural gas processing capacity. Enable expects to continue to grow the capacity of the super-header system through the planned addition of another new cryogenic processing plant and related gathering pipelines. The new plant, which will be located in Grady County, Oklahoma (the Bradley plant), will provide an additional 200 MMcf/d of processing capacity and is expected to be completed in the first quarter of 2015.

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

Enable's Transportation and Storage segment. Enable's natural gas transportation and storage business segment consists of its interstate pipelines, its intrastate pipelines and its storage assets. Enable provides pipeline takeaway capacity for natural gas producers from supply basins to market hubs and critical natural gas supply for industrial end users and utilities, such as local distribution companies (LDCs) and power generators. Enable's interstate pipeline system, including SESH, includes approximately 7,900 miles of transportation pipelines and extends from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois. Enable's eight storage facilities in Oklahoma, Louisiana and Illinois have 86.5 Bcf of storage capacity.

Enable generates revenue primarily by charging demand fees pursuant to applicable tariffs for the transportation and storage of natural gas on its system.

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

SESH. CenterPoint Southeastern Pipelines Holding, LLC, a wholly owned subsidiary of CERC, owned a 25.05% interest in SESH as of December 31, 2013. SESH owns a 1.0 Bcf per day, 274-mile interstate pipeline that runs from the Perryville Hub in Louisiana to Coden, Alabama. 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.

On May 1, 2013, CenterPoint Energy contributed a 24.95% interest in SESH to Enable. CERC has certain put rights, and Enable has certain call rights, exercisable with respect to the 25.05% interest in SESH retained by CERC, under which CERC would contribute its retained interest in SESH, in exchange for a specified number of limited partner units in Enable and a cash payment, payable either from CERC to Enable or from Enable to CERC, for changes in the value of SESH. Affiliates of Spectra Energy Corp own the remaining 50% interest in SESH.

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.

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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 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 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 the 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 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 Gas Operations 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. Gas Operations expects to be able to renew expiring franchises. In most cases, franchises to provide natural gas utility services are not exclusive.

Substantially all of Gas Operations 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 Gas Operations that have retained original jurisdiction. In certain of its jurisdictions, Gas Operations 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 Gas Operations' ongoing regulatory proceedings, see “Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters — Gas Operations” 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 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 — EGT, MRT and SESH — are subject to regulation by 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 Commodity 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 LDC served by an interstate natural gas pipeline. Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. The rates under Section 311 are maximum rates and 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 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 FERC for Section 311 service, or failure to comply with the terms and conditions of service established in the pipeline's FERC-approved Statement of Operating Conditions could result in the assertion of federal NGA jurisdiction by

FERC and/or the imposition of administrative, civil and criminal penalties, as described 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 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 HLPESA 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 (HCAs). 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 health, safety and the environment. As an owner or operator of natural gas distribution systems, and electric transmission and distribution 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 deemed in non-compliance 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 equipment;

acquire permits for facility operations;

modify, upgrade or replace existing and proposed equipment; and

clean up 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 disposed or otherwise 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 different from the amounts we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in 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, however, 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 all material current environmental and safety laws and regulations that relate to our operations. We believe that we are in substantial compliance with all of these environmental laws and regulations.

Global Climate Change

In recent years, there has been increasing public debate regarding the potential impact on global climate change by various “greenhouse gases” (GHGs) such as carbon dioxide, a byproduct of burning fossil fuels, and methane, the principal component of the natural gas that we transport and deliver to customers. The United States Congress has, from time to time, considered adopting legislation to reduce emissions of GHGs, and there has been a wide-ranging policy debate, both nationally and internationally, regarding the impact of these gases and possible means for their regulation. Some of the proposals would require industrial sources to meet stringent new standards that would require substantial reductions in carbon emissions. In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. Following a finding by the U.S. Environmental Protection Agency (EPA) that certain GHGs represent an endangerment to human health, the EPA adopted two sets of rules regulating GHG emissions under the Clean Air Act. One requires a reduction in emissions of GHGs from motor vehicles beginning January 2, 2011. The other regulates emissions of GHGs from certain large stationary sources under the Clean Air Act's Prevention of Significant Deterioration and Title V programs, commencing when the motor vehicle standards took effect on January 2, 2011. Also, the EPA adopted its “Mandatory Reporting of Greenhouse Gases Rule” that requires the annual calculation and reporting of GHG emissions from natural gas transmission, gathering, processing and distribution systems and electric distribution systems that emit 25,000 metric tons or more of CO₂ equivalent per year. These additional reporting requirements began in 2012 and we are currently in compliance. These permitting and reporting requirements could lead to further regulation of GHGs by the EPA.

Although the adoption of new legislation is uncertain, action by the EPA to impose new standards and reporting requirements regarding GHG emissions continues. In addition, many states and regions of the United States have begun to regulate GHGs. 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 businesses could be adversely affected through lower gas sales, and Enable's businesses could experience lower revenues. 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 and the operations of Enable 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, 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 continues to adopt amendments to its regulations regarding maximum achievable control technology for stationary internal combustion engines (sometimes referred to as the RICE MACT rule), the most recent being January 14, 2013. On August 29, 2013, the EPA announced that it was reconsidering three issues related to the RICE MACT rule, but the agency has not subsequently issued a rule proposal. Compressors and back up electrical generators used by our Natural Gas Distribution segment are generally compliant. Additional rules are expected to be proposed by the EPA this year for compliance by 2016. We believe, however, that our operations will not be materially adversely affected by such requirements.

In addition, on August 16, 2012, the EPA published final rules that establish new air emission control requirements for natural gas and NGL production, processing and transportation activities, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, and National Emission Standards for Hazardous Air Pollutants (NESHAPS) to address hazardous air pollutants frequently associated with gas production and processing activities. The finalized regulations establish specific new requirements for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants and certain other equipment. The final rules under NESHAPS include maximum achievable control technology standards for “small” glycol dehydrators that are located at major sources of hazardous air pollutants and modifications to the leak detection standards for valves. Compliance with such rules is not expected to result in significant costs that would adversely impact our results of operations.

Water Discharges

Our operations and the operations of Enable 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 and the operations of Enable 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. In Minnesota, CERC has completed remediation on two sites, other than ongoing monitoring and water treatment. There are five remaining sites in CERC's Minnesota service territory. CERC believes that it has no liability with respect to two of these sites.

As of December 31, 2013, CERC had recorded a liability of \$14 million for remediation of these Minnesota sites. The estimated range of possible remediation costs for the sites CERC believes it has responsibility for was \$6 million to \$41 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 be dependent upon the number of sites to be remediated, the participation of other potentially responsible parties (PRPs), if any, and the remediation methods used. The Minnesota Public Utilities Commission includes approximately \$285,000 annually in rates to fund normal on-going remediation costs. As of December 31, 2013, CERC had collected \$6.3 million from insurance companies to be used for future environmental remediation.

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 and CERC do not expect the ultimate outcome of these investigations will have a material adverse impact 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. We anticipate that additional claims like those received may be asserted in the future. 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. 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, 2013, we had 8,591 full-time employees, 1,099 of which are seconded to Enable and included below under the Midstream Investments business segment. The following table sets forth the number of our employees by business segment:

Business Segment	Number	Number Represented by Unions or Other Collective Bargaining Groups
Electric Transmission & Distribution	2,629	1,277
Natural Gas Distribution	3,475	1,303
Energy Services	140	—
Midstream Investments	1,099	—
Other Operations	1,248	—
Total	8,591	2,580

As of December 31, 2013, approximately 30% of our employees were covered by collective bargaining agreements.

EXECUTIVE OFFICERS

(as of February 14, 2014)

Name	Age	Title
Milton Carroll	63	Executive Chairman
Scott M. Prochazka	47	President and Chief Executive Officer and Director
Scott E. Rozzell	64	Executive Vice President, General Counsel and Corporate Secretary
Thomas R. Standish	64	Executive Vice President
Gary L. Whitlock	64	Executive Vice President and Chief Financial Officer
Tracy B. Bridge	55	Executive Vice President and President, Electric Division
Joseph B. McGoldrick	60	Executive Vice President and President, Gas Division

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 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 to 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 Gridwise Alliance, Edison Electric Institute, American Gas Association and Greater Houston Partnership.

Scott E. Rozzell has served as Executive Vice President, General Counsel and Corporate Secretary of CenterPoint Energy since September 2002. He served as Executive Vice President and General Counsel of the Delivery Group of Reliant Energy from March 2001 to September 2002. Before joining Reliant Energy in 2001, Mr. Rozzell was a senior partner in the law firm of Baker Botts L.L.P. He currently serves on the Board of Directors of Powell Industries, Inc.

Thomas R. Standish has served as Executive Vice President of CenterPoint Energy since May 2011. He previously served as Senior Vice President and Group President-Regulated Operations of CenterPoint Energy from August 2005 to May 2011; as Senior Vice President and Group President and Chief Operating Officer of CenterPoint Houston from June 2004 to August 2005;

and as President and Chief Operating Officer of CenterPoint Houston from August 2002 to June 2004. He served as President and Chief Operating Officer for both electricity and natural gas for Reliant Energy's Houston area from 1999 to August 2002.

Gary L. Whitlock has served as Executive Vice President and Chief Financial Officer of CenterPoint Energy since September 2002. He served as Executive Vice President and Chief Financial Officer of the Delivery Group of Reliant Energy from July 2001 to September 2002. Mr. Whitlock served as the Vice President, Finance and Chief Financial Officer of Dow AgroSciences, a subsidiary of The Dow Chemical Company, from 1998 to 2001. He currently serves on the Board of Directors of KiOR, Inc.

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 the Greater Houston Chapter of the American Red Cross.

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.

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 Midstream Partners, LP (Enable), a midstream 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 Affecting Our Electric Transmission & Distribution Business

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, 2013, CenterPoint Houston did business with approximately 70 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 not made 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, Just Energy Group, Inc. (Just Energy Group) and Energy Future Holdings. CenterPoint Houston's aggregate billed receivables balance from REPs as of December 31, 2013 was \$172 million. Approximately 38%, 8% and 8% of this amount was owed by affiliates of NRG, Just Energy Group and Energy Future Holdings, respectively. In the fourth quarter of 2013, Energy Future Holdings publicly disclosed that it had engaged in discussions with certain of its creditors with respect to the capital structure of Energy Future Holdings and its affiliates, including the possibility of a restructuring transaction in bankruptcy. The disclosures do not make clear whether those discussions included or addressed the capital structure of affiliates of Energy Future Holdings that are REPs. 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.

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 expenses at any given time. 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.

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.

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.

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 Gas Operations 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 expenses at any given time. 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 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.

CERC's natural gas distribution and energy services businesses 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 Gas Operations, 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) apply downward demand pressure on natural gas consumption 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.

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.

Risk Factors Associated with Our Consolidated Financial Condition

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

As of December 31, 2013, we had \$8.4 billion of outstanding indebtedness on a consolidated basis, which includes \$3.4 billion of non-recourse transition and system restoration bonds. As of December 31, 2013, approximately \$593 million principal amount of this debt is required to be paid through 2016. This amount excludes principal repayments of approximately \$1.1 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, 2013, CenterPoint Houston had approximately \$1.9 billion aggregate principal amount of general mortgage bonds outstanding under the General Mortgage, including (a) \$290 million held in trust to secure pollution control bonds that are not reflected in our consolidated financial statements because we are both the obligor on the bonds and the current owner of the bonds, (b) approximately \$118 million held in trust to secure pollution control bonds for which we are obligated and (c) approximately \$183 million held in trust to secure pollution control bonds for which CenterPoint Houston is obligated. Additionally, as of December 31, 2013, 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 \$3.9 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, 2013. 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.

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 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. 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.

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 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.

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 are subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of natural gas pipelines and distribution systems, and electric transmission and distribution 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 deemed in non-compliance 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 equipment;

acquire permits for facility operations;

modify or replace existing and proposed equipment; and

clean up 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 disposed or otherwise 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 natural 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.

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

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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 \$58 million as of December 31, 2013. Based on market conditions in the fourth quarter of 2013 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. 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 (now an affiliate of NRG) 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, 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-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.

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; and

- catastrophic events such as fires, earthquakes, explosions, floods, droughts, hurricanes, 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 merger and acquisition activities may not be successful or may result in completed acquisitions that do not perform as anticipated.

From time to time, we have made and may continue to make acquisitions of businesses and assets. However, suitable acquisition candidates may not continue to be available on terms and conditions we 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 may assume liabilities that were not disclosed to us, that exceed our estimates, or for which our rights to indemnification from the seller are limited;

- we may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems; and

- acquisitions, or the pursuit of acquisitions, could disrupt our ongoing businesses, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures.

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 for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect 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.

The United States Congress has from time to time considered adopting legislation to reduce emissions of GHGs, and there has been a wide-ranging policy debate, both nationally and internationally, regarding the impact of these gases and possible means for their regulation. In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues, such as the United Nations Climate Change Conference in Doha, Qatar in 2012. 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. In addition, the EPA expanded its existing GHG emissions reporting requirements to include upstream petroleum and natural gas systems that emit 25,000 metric tons or more of CO₂ equivalent per year. 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 our 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.

Additional Risk Factors Affecting Our Interests in Enable Midstream Partners, LP

We hold a substantial limited partnership interest in Enable (58.3% of Enable's outstanding limited partnership interests as of December 31, 2013), 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. 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 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.

Prior to an initial public offering of Enable, Enable is obligated to distribute 100% of its distributable cash (as such term is defined in its partnership agreement) to its limited partners each fiscal quarter within 45 days following the end of the applicable quarter. Following an initial public offering of Enable, (i) we expect that both CERC Corp. and OGE will hold their limited partnership interests in Enable in the form of both common units and subordinated units, and (ii) Enable is expected to pay a specified minimum quarterly distribution 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 following is initial public offering, 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 and crude oil that it handles;
- the prices of, levels of production of, and demand for natural gas and crude oil;
- the volume of natural gas 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.

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

Enable is controlled equally by CERC Corp. and OGE, who each own 50% of the management rights in the general partner of Enable. The general partner of Enable is currently governed by a board made up of an equal number of

representatives designated by each of us and OGE and an independent director. In addition, until the completion of Enable's initial public offering, ArcLight will have approval rights over certain material activities of Enable, including material increases in capital expenditures and certain equity issuances, entering into transactions with related parties, and acquiring, pledging or disposing of certain material assets. Following completion of Enable's initial public offering, the board of directors of Enable's general partner is expected to be 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 up to 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.

We may not realize the benefits we expect from our interests in Enable.

Enable may under-perform, causing our financial results to differ from our own or the investment community's expectations. In addition, Enable may not be able to achieve anticipated operational and commercial synergies or realize expected growth opportunities. The success of Enable will in part depend on its ability to integrate the operations of the businesses we contributed to Enable with those contributed by OGE and ArcLight. The integration process may be complex, costly and time-consuming. The potential difficulties of integrating the operations include, among others:

- implementing our business plan for the combined business;
- changes in applicable laws and regulations or conditions imposed by regulators;
- retaining key employees;
- operating risks inherent in the contributed businesses;
- realizing growth, revenue and expense targets; and
- unanticipated issues, costs, obligations and liabilities.

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. 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. 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 Group (Laclede), OGE, American Electric Power Company, Inc. (AEP) and Exxon Mobil Corporation (Exxon). Enable's interstate transportation and storage assets were designed and built to serve affiliates of CenterPoint Energy, Laclede, OGE and AEP.

Enable-Mississippi River Transmission, LLC's (MRT) firm transportation and storage contracts with Laclede are scheduled to expire in 2015 and 2016. The primary terms of Enable Gas Transmission, LLC's (EGT) firm transportation and storage contracts with CERC's natural gas distribution business will expire in 2018.

Enable's firm transportation contract with an affiliate of AEP expires January 1, 2015 and will remain in effect from year to year thereafter unless either party provides written notice of termination to the other party at least 180 days prior to the commencement of the succeeding annual period. The stated term of the OG&E transportation and storage contract expired April 30, 2009, but the contract remained in effect from year to year thereafter. On January 31, 2014, OG&E provided written notice of termination of the contract, effective April 30, 2014. Negotiations regarding the new contract are ongoing, and there can be no

assurance that the new contract will be agreed upon, or, if agreed upon, that the terms of the new contract will be as favorable to Enable as the expiring contract.

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 consolidated 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 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 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 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 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 or crude oil prices can have a negative impact on exploration, development and production activity and, if sustained, could lead to decreases in such activity. A sustained decline could also lead producers to shut in production from their existing wells. Sustained reductions in exploration or production activity in 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 condition, 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, as several of the formations in the unconventional resource basins 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 results of operations and distributable cash flow.

Enable's industry is highly competitive, and increased competitive pressure could adversely affect its 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 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 extensive investment in capital improvements and additions. 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 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 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, LNG, NGLs and crude oil, actions taken by foreign natural gas and oil producing nations, the availability of local, intrastate and interstate transportation systems, the availability and marketing of competitive fuels, the

impact of energy conservation efforts, technological advances affecting energy consumption and the extent of governmental regulation and taxation.

Enable's keep-whole natural gas processing arrangements 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 pays to the producer the natural gas equivalent Btu value of raw natural gas received from the producer in the form of either processed natural gas or its cash equivalent. The processor is generally entitled to retain the processed NGLs and to sell them for its own account. Accordingly, the processor's margin is a function of the difference between the value of the NGLs produced and the cost of the processed natural gas used to replace the natural gas equivalent Btu value of those NGLs. Therefore, if natural gas prices increase and NGL prices do not increase by a corresponding amount, the processor has to replace the Btu of natural gas at higher prices and processing margins are negatively affected.

Under Enable's percent-of-proceeds and percent-of-liquids natural gas processing agreements, the processor generally gathers raw natural gas from producers at the wellhead, transports the natural gas through its gathering system, processes the natural gas and sells the processed natural gas and/or NGLs at prices based on published index prices. The price paid to producers is based on an agreed percentage of the actual proceeds of the sale of processed natural gas, NGLs or both, or the expected proceeds based on an index price. These arrangements expose Enable to risks associated with the price of natural gas and NGLs.

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 initial operations on a new crude oil gathering pipeline system in North Dakota's Bakken shale formation, and Enable expects to place additional related assets in service in 2014. The gathering system, located in Dunn and McKenzie Counties in North Dakota, has a planned capacity of up to 19,500 barrels per day. These facilities are the first crude oil gathering system 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.

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.

"Negotiated rate" 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 a prolonged outage or disruption could ultimately result in a reduction in the volume of NGLs Enable is able to produce. Additionally, Enable depends on third parties to provide electricity for compression at many of its facilities. Since E