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 1-13265

CenterPoint Energy Resources Corp.

(Exact name of registrant as specified in its charter)

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

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

Title of Each Class	Name of Each Exchange On Which Registered
6.625% Senior Notes due 2037	New York Stock Exchange

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

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

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

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

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

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

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

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

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

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

The aggregate market value of the common equity held by non-affiliates as of June 30, 2013: None

TABLE OF CONTENTS

We meet the conditions specified in General Instruction I(1)(a) and (b) of Form 10-K and are thereby permitted to use the reduced disclosure format for wholly owned subsidiaries of reporting companies specified therein. Accordingly, we have omitted from this report the information called for by Item 10 (Directors, Executive Officers, and Corporate Governance), Item 11 (Executive Compensation), Item 12 (Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters) and Item 13 (Certain Relationships and Related Transactions, and Director Independence) of Form 10-K. In lieu of the information called for by Item 6 (Selected Financial Data) and Item 7 (Management's Discussion and Analysis of Financial Condition and Results of Operations) of Form 10-K, we have included, under Item 7, Management's Narrative Analysis of Results of Operations to explain the reasons for material changes in the amount of revenue and expense items between 2013, 2012 and 2011.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

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

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

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

PART I

Item 1. *Business*

OUR BUSINESS

Overview

We own and operate natural gas distribution systems in six states. We also offer variable and fixed-price physical natural gas supplies primarily to commercial and industrial customers and gas utilities. As of December 31, 2013, we also owned approximately 58.3% of the limited partner interests in Enable Midstream Partners, LP (Enable), an unconsolidated partnership jointly controlled with OGE Energy Corp., which owns, operates and develops natural gas and crude oil infrastructure assets. References to "we," "us," and "our" mean CenterPoint Energy Resources Corp. (CERC Corp., together with our subsidiaries, CERC). We are an indirect wholly owned subsidiary of CenterPoint Energy, Inc. (CenterPoint Energy), a public utility holding company.

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

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

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

Natural Gas Distribution

Our natural gas distribution business (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%), Mieco 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 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

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

In 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 CenterPoint Energy's Risk Oversight Committee, defines authorized and prohibited trading instruments and trading limits. CES is a physical marketer of natural gas and uses a variety of tools, including pipeline and storage capacity, financial instruments and physical commodity purchase contracts, to support its sales. 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 our 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 Corp., 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, we 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 unallocated corporate costs and inter-segment eliminations.

Financial Information About Segments

For financial information about our segments, see Note 15 to our consolidated financial statements, which note is incorporated herein by reference.

REGULATION

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

Federal Energy Regulatory Commission

The FERC has jurisdiction under the Natural Gas Act and the Natural Gas Policy Act of 1978, as amended, to regulate the transportation of natural gas in interstate commerce and natural gas sales for resale in interstate commerce that are not first sales. The FERC regulates, among other things, the construction of pipeline and related facilities used in the transportation and storage of natural gas in interstate commerce, including the extension, expansion or abandonment of these facilities. The FERC has authority to prohibit market manipulation in connection with FERC-regulated transactions and to impose significant civil and criminal penalties for statutory violations and violations of the FERC's rules or orders. Our Energy Services business segment markets natural gas in interstate commerce pursuant to blanket authority granted by the FERC.

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

State and Local Regulation

In almost all communities in which 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 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 Narrative Analysis of Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report, which discussion is incorporated herein by reference.

Department of Transportation

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

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

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

In December 2011, Congress passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Act). This act increases the maximum civil penalties for pipeline safety administrative enforcement actions; requires the DOT to study and report on the expansion of integrity management requirements and the sufficiency of existing gathering line regulations to ensure safety; requires pipeline operators to verify their records on maximum allowable operating pressure; and imposes new emergency response and incident notification requirements.

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

Midstream Investments - Rate and Other Regulation

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

Interstate Natural Gas Pipeline Regulation

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

Market Behavior Rules; Posting and Reporting Requirements

On August 8, 2005, Congress enacted the Energy Policy Act of 2005 (EPAct of 2005). Among other matters, the EPAct of 2005 amended the NGA to add an anti-manipulation provision that makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulation to be prescribed by the FERC and, furthermore, provides the FERC with additional civil penalty authority. On January 19, 2006, the FERC issued Order No. 670, a rule implementing the anti-manipulation provisions of the EPAct of 2005. The rules make it unlawful for any entity, directly or indirectly in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC or the purchase or sale of transportation services subject to the jurisdiction of the FERC, to (1) use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The EPAct of 2005 also amends the NGA and the Natural Gas Policy Act of 1978 (NGPA) to give the FERC authority to impose civil penalties for violations of these statutes and FERC's regulations, rules, and orders, up to $1 million per day per violation for violations occurring after August 8, 2005. Should Enable fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, it could be subject to substantial penalties and fines. In addition, the Commodity Futures Trading Commission (CFTC) is directed under the Commodities Exchange Act (CEA) to prevent price manipulations for the commodity and futures markets, including the energy futures markets. Pursuant to the Dodd-Frank Act and other authority, the CFTC has adopted anti-market manipulation regulations that prohibit fraud and price manipulation in the commodity and futures markets. The CFTC also has statutory authority to seek civil penalties of up to the greater of $1 million or triple the monetary gain to the violator for violations of the anti-market manipulation sections of the CEA.

Intrastate Natural Gas Pipeline and Storage Regulation

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

Intrastate natural gas transportation is largely regulated by the state in which the transportation takes place. An intrastate natural gas pipeline system may transport natural gas in interstate commerce provided that the rates, terms, and conditions of such transportation service comply with FERC regulation and Section 311 of the NGPA and Part 284 of the FERC's regulations. The NGPA regulates, among other things, the provision of transportation and storage services by an intrastate natural gas pipeline on behalf of an interstate natural gas pipeline or a 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 HLPSA which requires PHMSA to develop, prescribe, and enforce minimum federal safety standards for the transportation of hazardous liquids by pipeline, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of pipeline facilities. 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, 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 CO_2 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. Our revenues, operating costs and capital requirements could be adversely affected as a result of any regulatory action that would require installation of new control technologies or a modification of our operations or would have the effect of reducing the consumption of natural gas. Likewise, incentives to conserve energy or use energy sources other than natural gas could result in a decrease in demand for our services. Conversely, regulatory actions that effectively promote the consumption of natural gas because of its lower emissions characteristics would be expected to beneficially affect us and our natural gas-related businesses. At this point in time, however, it would be speculative to try to quantify the magnitude of the impacts from possible new regulatory actions related to GHG emissions, either positive or negative, on our businesses.

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

Air Emissions

Our operations 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. We and our predecessors operated manufactured gas plants (MGPs) in the past. In Minnesota, we have completed remediation on two sites, other than ongoing monitoring and water treatment. There are five remaining sites in our Minnesota service territory. We believe that we have no liability with respect to two of these sites.

As of December 31, 2013, we had recorded a liability of $14 million for remediation of these Minnesota sites. The estimated range of possible remediation costs for the sites we believe we have 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, we 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 us or may have been owned by one of our former affiliates. We do not expect the ultimate outcome of these investigations will have a material adverse impact on our financial condition, results of operations or cash flows.

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

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

EMPLOYEES

As of December 31, 2013, we had 4,714 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
Natural Gas Distribution	3,475	1,303
Energy Services	140	—
Midstream Investments	1,099	—
Total	4,714	1,303

As of December 31, 2013, approximately 28% of our employees were covered by collective bargaining agreements.

Item 1A. *Risk Factors*

The following, along with any additional legal proceedings identified or incorporated by reference in Item 3 of this report, summarizes the principal risk factors associated with our business.

Risk Factors Affecting Our Businesses

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

Our rates for Gas Operations are regulated by certain municipalities and state commissions based on an analysis of our invested capital and our expenses in a test year. Thus, the rates that we are allowed to charge may not match our 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 our costs and enable us to earn a reasonable return on our invested capital.

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

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

Our 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 our suppliers and customers to meet their obligations or otherwise adversely affect our liquidity and results of operations and financial condition.

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

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

If our credit rating were to decline, we might be required to post cash collateral under our shipping or hedging arrangements or in order to purchase natural gas. If a credit rating downgrade and the resultant cash collateral requirement were to occur at a time when we were experiencing significant working capital requirements or otherwise lacked liquidity, our results of operations, financial condition and cash flows could be adversely affected.

Our revenues and results of operations are seasonal.

A substantial portion of our revenues is derived from natural gas sales. Thus, our revenues and results of operations are subject to seasonality, weather conditions and other changes in natural gas usage, with revenues being higher during the winter months.

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

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

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

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 $2.3 billion of outstanding indebtedness on a consolidated basis. As of December 31, 2013, approximately $325 million of this debt is required to be paid through 2016. This amount excludes approximately $38 million borrowed from the money pool. Our future financing activities may be significantly affected by, among other things:

- general economic and capital market conditions;
- credit availability from financial institutions and other lenders;

- investor confidence in us and CenterPoint Energy and the markets in which we operate;
- maintenance of acceptable credit ratings by us and CenterPoint Energy;
- market expectations regarding our and CenterPoint Energy's future earnings and cash flows;
- market perceptions of our and CenterPoint Energy's ability to access capital markets on reasonable terms;
- our exposure to GenOn Energy, Inc. (GenOn) (formerly known as RRI Energy, Inc., Reliant Energy, Inc. and Reliant Resources, Inc.(RRI)), a wholly owned subsidiary of NRG Energy, Inc. (NRG) in connection with its indemnification obligations arising in connection with its separation from CenterPoint Energy;
- incremental collateral that may be required due to regulation of derivatives; and
- provisions of relevant tax and securities laws.

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

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

Our credit ratings and liquidity may be impacted by the creditworthiness and liquidity of our parent company and our affiliates. As of December 31, 2013, CenterPoint Energy and its subsidiaries other than us had approximately $269 million principal amount of debt 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, and indexed debt securities obligations. If CenterPoint Energy were to experience a deterioration in its creditworthiness or liquidity, our creditworthiness and liquidity could be adversely affected. In addition, CenterPoint Energy or its other subsidiaries or affiliates may from time to time acquire or dispose of assets or businesses or enter into joint ventures or other transactions that could adversely impact the credit capacity, credit ratings or liquidity of CenterPoint Energy or its other subsidiaries or affiliates, which, as a result, could adversely impact our credit ratings and liquidity. Also, from time to time we and other affiliates invest or borrow funds in the money pool maintained by CenterPoint Energy. If CenterPoint Energy or the affiliates that borrow any funds that we might invest from time to time in the money pool were to experience a deterioration in their creditworthiness or liquidity, our creditworthiness, liquidity and the repayment of notes receivable from CenterPoint Energy and our affiliates participating in the money pool could be adversely impacted.

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

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

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

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

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

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

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

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

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

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

Other Risks

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 gas gathering and processing 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.

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

Under some circumstances, we and CenterPoint Energy could incur liabilities associated with assets and businesses we and CenterPoint Energy no longer own. These assets and businesses were previously owned by Reliant Energy, Incorporated (Reliant Energy), a predecessor of CenterPoint Energy, directly or through subsidiaries, including us in some cases. Through a series of transactions, the assets and businesses were transferred to a predecessor of RRI.

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

Prior to the distribution of CenterPoint Energy's ownership in RRI to its shareholders, we had guaranteed certain contractual obligations of what became RRI’s trading subsidiary. When the companies separated, RRI agreed to secure us against obligations under the guarantees RRI had been unable to extinguish by the time of separation. Pursuant to such agreement, as amended in December 2007, RRI (now GenOn) agreed to provide to us cash or letters of credit as security against our obligations under our remaining guarantees for demand charges under certain gas transportation agreements if and to the extent changes in market conditions expose us to a risk of loss on those guarantees based on an annual calculation, with any required collateral to be posted each December. The undiscounted maximum potential payout of the demand charges under these transportation contracts, which will be in effect until 2018, was approximately $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, we could have to honor our guarantee and, in such event, any collateral provided as security may be insufficient to satisfy our obligations.

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

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

Cyber-attacks, 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 distribution of natural gas to our customers and the gathering, processing and transportation of natural gas or other commodities from Enable's gathering, processing and pipeline facilities, are dependent on communications among Enable's facilities and with third-party systems that may be delivering natural gas or other commodities into or receiving natural gas and other products from Enable's facilities. Disruption of those communications, whether caused by physical disruption such as storms or other natural phenomena, by failure of equipment or technology, or by manmade events, such as cyber-attacks or acts of terrorism, may disrupt our ability or Enable's ability to conduct operations and control assets. Cyber-attacks could also result in the loss of confidential or proprietary data or security breaches of other information technology systems that could disrupt operations and critical business functions, adversely affect reputation, and subject us or Enable to possible legal claims and liability. Neither we nor Enable is fully insured against all cyber-security risks, any of which could have a material adverse effect on either our, or Enable's, results of operations, financial condition and cash flows. In addition, gas distribution and pipeline systems may be targets of terrorist activities that could disrupt either our or Enable's ability to conduct our respective businesses and have a material adverse effect on either our or Enable's results of operations, financial condition and cash flows.

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 of CO_2 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 and consumer of natural gas in our pipeline and gathering businesses, our or Enable'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 our operations or would have the effect of reducing the consumption of natural gas. Likewise, incentives to conserve energy or use energy sources other than natural gas could result in a decrease in demand for our services.

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 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.

MRT's firm transportation and storage contracts with Laclede are scheduled to expire in 2015 and 2016. The primary terms of EGT's 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 Enable does not own or operate any of these third-party pipelines or other facilities, their continuing operation is not within its control. If any of these third-party pipelines or other facilities become partially or fully unavailable for any reason, Enable’s results of operations and its ability to make cash distributions to unitholders could be adversely affected.

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

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

Enable conducts a portion of its operations through joint ventures, which subject it to additional risks that could have a material adverse effect on the success of these operations and Enable’s financial position and results of operations.

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

Enable’s joint venture arrangements may involve risks not otherwise present when operating assets directly. For example, Enable’s joint venture partners may share certain approval rights over major decisions or be in a position to take actions contrary to Enable’s instructions or requests or contrary to its policies or objectives.

These risks or the failure to continue Enable’s joint ventures or to resolve disagreements with Enable’s joint venture partners could adversely affect Enable’s ability to transact the business that is the subject of such joint venture, which would in turn negatively affect Enable’s financial condition and results of operations.

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

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

- damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters, acts of terrorism and actions by third parties;

- inadvertent damage from construction, vehicles, farm and utility equipment;

- leaks of natural gas, crude oil and other hydrocarbons or losses of natural gas and crude oil as a result of the malfunction of equipment or facilities;

- ruptures, fires and explosions; and

- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

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

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

Enable expects that it will distribute all of its “available cash” to its unitholders following its initial public offering. As a result, Enable is expected to rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund acquisitions and expansion capital expenditures. As a result, to the extent Enable is unable to finance growth externally, Enable’s cash distribution policy will significantly impair its ability to grow. In addition, because Enable is expected to distribute all of its available cash, its growth may not be as fast as businesses that reinvest their available cash to expand ongoing operations.

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

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

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

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

As of December 31, 2013, Enable had approximately $1.9 billion of long-term debt outstanding and $200 million of short-term debt outstanding, excluding the premiums on senior notes. Enable has $363 million of long-term notes payable-affiliated companies due to CenterPoint Energy. Enable has a $1.4 billion revolving credit facility for working capital, capital expenditures and other partnership purposes, including acquisitions, of which $1.1 billion was available as of December 31, 2013. As of January 2014, Enable has the ability to issue up to $1.4 billion in commercial paper, subject to available borrowing capacity under its revolving credit facility and market conditions. Enable will continue to have the ability to incur additional debt, subject to limitations in its credit facilities. The levels of Enable’s debt could have important consequences, including the following:

- the ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or the financing may not be available on favorable terms, if at all;

- a portion of cash flows will be required to make interest payments on the debt, reducing the funds that would otherwise be available for operations, future business opportunities and distributions;

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

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

Enable's ability to service its debt will depend upon, among other things, its future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond Enable's control. If operating results are not sufficient to service current or future indebtedness, Enable may be forced to take actions such as reducing distributions, reducing or delaying business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing debt, or seeking additional equity capital. These actions may not be effected on satisfactory terms, or at all.

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

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

- permit its subsidiaries to incur or guarantee additional debt;

- incur or permit to exist certain liens on assets;

- dispose of assets;

- merge or consolidate with another company or engage in a change of control;

- enter into transactions with affiliates on non-arm's length terms; and

- change the nature of its business.

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

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

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

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

There is inherent risk of the incurrence of environmental costs and liabilities in Enable's operations due to its handling of natural gas, NGLs and crude oil, air emissions related to its operations and historical industry operations and waste disposal practices. These activities are subject to stringent and complex federal, state and local laws and regulations governing environmental protection, including the discharge of materials into the environment and the protection of plants, wildlife, and natural and cultural resources.

These laws and regulations can restrict or impact Enable's business activities in many ways, such as restricting the way it can handle or dispose of wastes or requiring remedial action to mitigate pollution conditions that may be caused by its operations or that are attributable to former operators. Joint and several strict liability may be incurred, without regard to fault, under certain of these environmental laws and regulations in connection with discharges or releases of wastes on, under or from Enable's properties and facilities, many of which have been used for midstream activities for a number of years, oftentimes by third parties not under its control. Private parties, including the owners of the properties through which Enable's gathering systems pass and facilities where its wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance, as well as to seek damages for non-compliance, with environmental laws and regulations or for personal injury or property damage. For example, an accidental release from one of Enable's pipelines could subject it to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. Enable may be unable to recover these costs from insurance. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase compliance costs and the cost of any remediation that may become necessary. Further, stricter requirements could negatively impact Enable's customers' production and operations, resulting in less demand for its services.

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. Many of Enable's customers commonly use hydraulic fracturing techniques in their drilling and completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas commissions. In addition, Congress from time to time has considered the adoption of legislation to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act (SDWA) and to require disclosure of the chemicals used in the hydraulic fracturing process. Some states have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where Enable's oil and natural gas exploration and production customers operate, they could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells, some or all of which activities could adversely affect demand for Enable's services to those customers.

In addition, certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. A draft final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources is currently expected to be available for public comment and peer review in 2014. Moreover, the EPA has announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. President Obama created the Interagency Working Group on Unconventional Natural Gas and Oil by Executive Order on April 13, 2012, which is charged with coordinating and aligning federal agency research and scientific studies on unconventional natural gas and oil resources, including hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms.

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

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

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

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

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

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

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

Enable's crude oil gathering pipelines are subject to common carrier regulation by the FERC under the Interstate Commerce Act, or ICA. The ICA requires that Enable maintain tariffs on file with the FERC setting forth the rates it charges for providing transportation services, as well as the rules and regulations governing such services. The ICA requires, among other things, that Enable's rates must be "just and reasonable" and that it provides service in a manner that is nondiscriminatory.

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

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

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

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

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

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

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

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

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

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

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

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

None.

Item 2. ***Properties***

Character of Ownership

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

Natural Gas Distribution

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

Energy Services

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

Midstream Investments

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

Item 3. ***Legal Proceedings***

For a discussion of material legal and regulatory proceedings affecting us, please read "Business — Regulation" and "Business — Environmental Matters" in Item 1 of this report, "Management's Narrative Analysis of Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of this report and Note 13(d) to our consolidated financial statements, which information is incorporated herein by reference.

Item 4. ***Mine Safety Disclosures.***

Not applicable.

PART II

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

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

No dividends were paid to our parent in 2013, 2012 or 2011.

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

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

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

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

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

Background

We own and operate natural gas distribution systems in six states. 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. We are an indirect wholly owned subsidiary of CenterPoint Energy, Inc. (CenterPoint Energy).

Business Segments

Because we are an indirect wholly owned subsidiary of CenterPoint Energy, our determination of reportable segments considers the strategic operating units under which CenterPoint Energy manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments. In this section, we discuss our results on a consolidated basis and individually for each of our business segments. We also discuss our liquidity, capital resources and critical accounting policies. The results of our business operations are significantly impacted by weather, customer growth, economic conditions, cost management, competition, rate proceedings before regulatory agencies and other actions of the various regulatory agencies to which we are subject. Our natural gas distribution services are subject to rate regulation. A summary of our reportable business segments as of December 31, 2013 is set forth below:

Natural Gas Distribution

We own and operate our regulated natural gas distribution business (Gas Operations), which engages in 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.

Energy Services

Our operations also include non-rate regulated natural gas sales to, and transportation services for, commercial and industrial customers in 21 states in the central and eastern regions of the United States.

Midstream Investments

We have a significant equity investment in Enable, an unconsolidated subsidiary that owns, operates and develops natural gas and crude oil assets. Our Midstream Investments segment includes equity earnings associated with the operations of Enable and a 25.05% interest in SESH currently owned by CERC.

Other Operations

Our other operations business segment includes unallocated corporate costs and inter-segment eliminations.

EXECUTIVE SUMMARY

Factors Influencing Our Businesses

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

To the extent adverse economic conditions affect our suppliers and customers, results from our energy delivery businesses may suffer. Reduced demand and lower energy prices could lead to financial pressure on some of our customers who operate within the energy industry. Also, adverse economic conditions, coupled with concerns for protecting the environment, may cause consumers to use less energy or avoid expansions of their facilities, resulting in less demand for our services.

Performance of our Natural Gas Distribution business segment is significantly influenced by the number of customers and energy usage per customer. Weather conditions can have a significant impact on energy usage, and we compare our results on a weather adjusted basis. In 2012, every state in which we distribute natural gas had the warmest winter on record. In 2013, we experienced a colder than normal spring and very cold weather in November and December in Houston and all of the states in which we have gas customers. In recent years, customers have typically reduced their energy consumption, and reduced consumption can adversely affect our results. However, due to more affordable energy prices and continued economic improvement in the areas we serve, the trend toward lower usage has slowed in some of the areas we serve. In addition, in many of our service areas, particularly in the Houston area and in Minnesota, we have benefited from a growth in the number of customers that also tends to mitigate the effects of reduced consumption. We anticipate that this trend will continue as the regions' economies resume typical growth. The profitability of our businesses is influenced significantly by the regulatory treatment we receive from the various state and local regulators who set our gas distribution rates.

Our Energy Services business segment contracts with customers for transportation, storage and sales of natural gas on an unregulated basis. Its operations serve customers in the central and eastern regions of the United States. The segment benefits from favorable price differentials, either on a geographic basis or on a seasonal basis. While this business utilizes financial derivatives to hedge its exposure to price movements, it does not engage in speculative or proprietary trading and maintains a low value at risk level, or VaR, to avoid significant financial exposures. Lower geographic and seasonal price differentials during 2013, 2012 and 2011 adversely affected results for this business segment.

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

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

Factors Influencing Our Midstream Investments Segment

The results of our Midstream Investments segment are primarily dependent upon the results of Enable, which are driven primarily by the volume of natural gas that Enable gathers, processes and transports across its systems, which depends significantly on the level of production from natural gas wells connected to its systems. Aggregate production volumes are affected by the overall amount of drilling and completion activity, as production must be maintained or increased by new drilling or other activity, because the production rate of a natural gas well declines over time. Producers' willingness to engage in new drilling is determined by a number of factors, the most important of which are the prevailing and projected prices of natural gas and NGLs, the cost to drill and operate a well, the availability and cost of capital and environmental and government regulations. The level of drilling is expected to positively correlate with long-term trends in commodity prices. Similarly, production levels nationally and regionally generally tend to positively correlate with drilling activity.

To maintain and increase gathering throughput volumes on its systems, Enable must continue to contract its capacity to shippers, including producers and marketers. Enable's transportation and storage systems compete for customers based on the type of service a customer needs, operating flexibility, receipt and delivery points and geographic flexibility and available capacity and price. To maintain and increase Enable's transportation and storage volumes, it must continue to contract its capacity to shippers, including producers, marketers, LDCs, power generators and end-users.

Enable's operation and maintenance expenses are comprised primarily of labor expenses, lease costs, utility costs, insurance premiums and repairs and maintenance expenses. These expenses generally remain relatively stable across broad ranges of throughput volumes but can fluctuate from period to period depending on the mix of activities performed during that period and the timing of these expenses. The current high levels of crude oil exploration, development and production activities are increasing competition for personnel and equipment. This increased competition is placing upward pressure on the prices Enable pays for labor, supplies and miscellaneous equipment. To the extent Enable is unable to procure necessary services or offset higher costs, its operating results will be negatively affected.

Our Midstream Investments segment currently includes a 25.05% interest in SESH owned by CERC that may be contributed by CERC to Enable in the future, upon exercise of certain put or call rights under which CERC would contribute to Enable CERC's retained interest in SESH at a price equal to the fair market value of such interest at the time the put right or call right is exercised (which may be no earlier than May 2014 and May 2015 for a 24.95% and a 0.1% interest, respectively). If CERC were to exercise such put right or Enable were to exercise such call right, CERC's retained interest in SESH would be contributed to Enable in exchange for consideration consisting of a certain number of limited partnership units in Enable (subject to certain antidilution adjustments) for a 24.95% and a 0.1% interest in SESH, respectively, and, subject to certain restrictions, a cash payment, payable either from CERC to Enable or from Enable to CERC for changes in the value of SESH.

Significant Events

Enable Midstream Partners. 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 Midstream Partners, LP (Enable) as a private limited partnership. On May 1, 2013, the parties closed on the formation of Enable pursuant to the terms of the MFA. In connection with the closing (i) we converted our direct wholly owned subsidiary, CenterPoint Energy Field Services, LLC, a Delaware limited liability company (CEFS), into a Delaware limited partnership that became Enable, (ii) we contributed to Enable our equity interests in each of CenterPoint Energy Gas Transmission Company, LLC, which has been subsequently renamed Enable Gas Transmission, LLC (EGT), CenterPoint Energy - Mississippi River Transmission, LLC, which has been subsequently renamed Enable Mississippi River Transmission, LLC (MRT), certain of its other midstream subsidiaries, and a 24.95% interest in Southeast Supply Header, LLC (SESH), and (iii) OGE and ArcLight indirectly contributed 100% of the equity interests in Enogex LLC, which has been subsequently renamed Enable Oklahoma Intrastate Transmission, LLC, to Enable. Enable owns substantially all of our former Interstate Pipelines and Field Services business segments, except for our retained 25.05% interest in SESH.

As of December 31, 2013, we, 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 us and OGE; each own 50% of the management rights in the general partner of Enable. We and OGE also own a 40% and 60% interest, respectively, in the incentive distribution rights held by the general partner of Enable.

On May 1, 2013, Enable (i) entered into a $1.05 billion three-year senior unsecured term loan facility, (ii) repaid $1.05 billion of indebtedness owed to us, and (iii) entered into a $1.4 billion senior unsecured revolving credit facility.

As a result of the formation of Enable, we no longer have Interstate Pipelines or Field Services business segments. Enable is an unconsolidated subsidiary which we account for on an equity basis. Equity earnings associated with our interest in Enable and our retained 25.05% interest in SESH are reported under our Midstream Investments segment. For a further description of our reportable business segments, see Note 15 to our consolidated financial statements.

Debt Matters. In April 2013, we retired approximately $365 million aggregate principal amount of our 7.875% senior notes at their maturity. The retirement of senior notes was financed by us with the issuance of commercial paper.

In May 2013, we applied proceeds from Enable's May 1, 2013 debt repayment of $1.05 billion to the repayment of $357 million aggregate principal amount of our commercial paper and to the May 31, 2013 redemption of $160 million aggregate principal amount of our 5.95% senior notes due January 15, 2014 at 103.419% of their aggregate principal amount.

On September 9, 2013, our revolving credit facility was amended to, among other things, (i) reduce the size of the our facility from $950 million to $600 million and (ii) extend the scheduled termination date of the facility from September 9, 2016 to September 9, 2018.

In 2013, we reduced our money pool borrowings by $741 million and increased our outstanding commercial paper by $118 million.

CERTAIN FACTORS AFFECTING FUTURE EARNINGS

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

- state and federal legislative and regulatory actions or developments affecting various aspects of our businesses (including the businesses of Enable), including, among others, energy deregulation or re-regulation, pipeline integrity and safety, health care reform, financial reform, tax legislation and actions regarding the rates charged by our regulated businesses;
- state and federal legislative and regulatory actions or developments relating to the environment, including those related to global climate change;
- timely and appropriate rate actions that allow recovery of costs and a reasonable return on investment;
- the timing and outcome of any audits, disputes and other proceedings related to taxes;
- problems with construction, implementation of necessary technology or other issues with respect to major capital projects that result in delays or in cost overruns that cannot be recouped in rates;
- industrial, commercial and residential growth in our service territories and changes in market demand, including the effects of energy efficiency measures and demographic patterns;
- the timing and extent of changes in commodity prices, particularly natural gas and natural gas liquids (NGLs), and the effects of geographic and seasonal commodity price differentials;
- weather variations and other natural phenomena, including the impact of severe weather events on operations and capital;
- any direct or indirect effects on our facilities, operations and financial condition resulting from terrorism, cyber-attacks, data security breaches or other attempts to disrupt our businesses or the businesses of third parties, or other catastrophic events;
- the impact of unplanned facility outages;
- timely and appropriate regulatory actions allowing recovery of costs associated with any future hurricanes or natural disasters;
- changes in interest rates or rates of inflation;

- commercial bank and financial market conditions, our access to capital, the cost of such capital, and the results of our financing and refinancing efforts, including availability of funds in the debt capital markets;
- actions by credit rating agencies;
- effectiveness of our risk management activities;
- inability of various counterparties to meet their obligations to us;
- non-payment for our services due to financial distress of our customers;
- the ability of GenOn Energy, Inc. (formerly known as RRI Energy, Inc., Reliant Energy, Inc. and Reliant Resources, Inc.), a wholly owned subsidiary of NRG Energy, Inc. (NRG), and its subsidiaries to satisfy their obligations to us, including indemnity obligations, or obligations in connection with the contractual arrangements pursuant to which we are their guarantor;
- the outcome of litigation brought by or against us;
- our ability to control costs;
- the investment performance of our pension and postretirement benefit plans;
- our potential business strategies, including restructurings, joint ventures and acquisitions or dispositions of assets or businesses, which we cannot assure you will be completed or will have the anticipated benefits to us;
- acquisition and merger activities involving us or our competitors;
- future economic conditions in regional and national markets and their effect on sales, prices and costs;
- the performance of Enable, the amount of cash distributions we receive from Enable, the value of our interest in Enable and factors that may have a material impact on such performance, cash distributions and value, including certain of the factors specified above and:
    - the integration of the operations of the businesses we contributed to Enable with those contributed by OGE and ArcLight;
    - the achievement of anticipated operational and commercial synergies and expected growth opportunities, and the successful implementation of its business plan;
    - competitive conditions in the midstream industry and actions taken by Enable's customers and competitors, including the extent and timing of the entry of additional competition in the markets served by Enable;
    - the timing and extent of changes in the supply of natural gas and associated commodity prices, particularly prices of natural gas and NGLs, the competitive effects of the available pipeline capacity in the regions served by Enable and the effects of geographic and seasonal commodity price differentials, including the effects of these circumstances on re-contracting available capacity on Enable's interstate pipelines;
    - the demand for natural gas, NGLs and transportation and storage services;
    - changes in tax status;
    - access to growth capital;
    - the availability and prices of raw materials for current and future construction projects;
    - the timing and terms of Enable’s planned initial public offering, the actual consummation of which is subject to market conditions, regulatory requirements and other factors; and
- other factors we discuss under “Risk Factors” in Item 1A of this report and in other reports we file from time to time with the SEC.

CONSOLIDATED RESULTS OF OPERATIONS

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

The following table sets forth selected financial data (in millions) for the years ended December 31, 2013, 2012 and 2011, followed by a discussion of our consolidated results of operations based on operating income. We have provided a reconciliation of consolidated operating income to net income below.

	Year Ended December 31,		
	2013	2012	2011
Revenues	$ 5,522	$ 4,901	$ 6,102
Expenses:			
Natural gas	3,908	2,873	4,055
Operation and maintenance	828	951	964
Depreciation and amortization	230	285	262
Taxes other than income taxes	155	146	159
Goodwill impairment	—	252	—
Total	5,121	4,507	5,440
Operating Income	401	394	662
Interest and other finance charges	(154)	(179)	(190)
Equity in earnings of unconsolidated affiliates	188	31	30
Step acquisition gain	—	136	—
Other income, net	—	1	1
Income Before Income Taxes	435	383	503
Income Tax Expense	371	246	187
Net Income	$ 64	$ 137	$ 316

2013 Compared to 2012. We reported net income of $64 million for 2013 compared to $137 million for 2012. The decrease in net income of $73 million was primarily due to to a $136 million non-cash step acquisition gain related to the acquisition of an additional 50% interest in Waskom in 2012 and a $125 million increase in income tax expense discussed below. These decreases were partially offset by a $157 million increase in equity earnings of unconsolidated affiliates, a $25 million decrease in interest expense and a $7 million increase in operating income (discussed below by segment). Operating income in 2012 included a $252 million non-cash goodwill impairment charge.

Income Tax Expense. We reported an effective tax rate of 85.3% for 2013 compared to 64.2% for the same period in 2012. Our effective tax rate for 2013 increased by 21.1% primarily as a result of the formation of Enable with deferred tax expense of $225 million related to the book-to-tax basis difference for contributed non-tax deductible goodwill and a tax benefit of $27 million associated with the remeasurement of state deferred taxes at formation. In addition, we recognized a tax benefit of $2 million based on the settlement with the Internal Revenue Service of outstanding tax claims for the 2002 and 2003 audit cycles. Our effective tax rate for 2013 was approximately 40.2% excluding the tax effects from the adjustments described above.

Our effective tax rate for 2012 of 64.2% was primarily impacted by an increase in tax expense of $88 million related to the non-tax deductible impairment of goodwill of $252 million. Our effective tax rate for 2012 was approximately 41.2% excluding the tax effects from the adjustment described above.

2012 Compared to 2011. We reported net income of $137 million for 2012 compared to $316 million for 2011. The decrease in net income of $179 million was primarily due to a $268 million decrease in operating income (discussed by segment below), including a $252 million non-cash goodwill impairment charge, and a $59 million increase in income tax expense, which were partially offset by a $136 million step acquisition gain related to the acquisition of an additional 50% interest in Waskom and an $11 million decrease in interest and other finance charges due to lower levels of debt.

Income Tax Expense. We reported an effective tax rate of 64.2% for 2012 compared to 37.2% for 2011. The increase in our effective tax rate is primarily due to the goodwill impairment of $252 million which is non-deductible for tax in 2012 and higher state tax expense compared to 2011 related to benefits recognized in that prior period for lower blended state rates. The increased rate was partially offset by the release of income tax reserves of $7 million.

RESULTS OF OPERATIONS BY BUSINESS SEGMENT

The following table presents operating income (loss) (in millions) for each of our business segments for 2013, 2012 and 2011. Included in revenues are intersegment sales. We account for intersegment sales as if the sales were to third parties, that is, at current market prices.

Operating Income (Loss) by Business Segment

	Year Ended December 31,		
	2013	2012	2011
Natural Gas Distribution	$ 263	$ 226	$ 226
Energy Services	13	(250)	6
Interstate Pipelines	72	207	248
Field Services	73	214	189
Other Operations	(20)	(3)	(7)
Total Consolidated Operating Income	$ 401	$ 394	$ 662

Natural Gas Distribution

The following table provides summary data of our Natural Gas Distribution business segment for 2013, 2012 and 2011 (in millions, except throughput and customer data):

	Year Ended December 31,		
	2013	2012	2011
Revenues	$ 2,863	$ 2,342	$ 2,841
Expenses:			
Natural gas	1,607	1,196	1,675
Operation and maintenance	667	637	655
Depreciation and amortization	185	173	166
Taxes other than income taxes	141	110	119
Total expenses	2,600	2,116	2,615
Operating Income	$ 263	$ 226	$ 226
Throughput (in Bcf):			
Residential	182	140	172
Commercial and industrial	265	243	251
Total Throughput	447	383	423
Number of customers at end of period:			
Residential	3,090,966	3,058,695	3,036,267
Commercial and industrial	247,100	246,413	246,220
Total	3,338,066	3,305,108	3,282,487

2013 Compared to 2012. Our Natural Gas Distribution business segment reported operating income of $263 million for 2013 compared to $226 million for 2012. Operating income increased $37 million primarily due to increased usage as a result of colder weather compared to the prior year, partially mitigated by weather hedges and weather normalization adjustments ($29 million), rate increases ($29 million), and increased economic activity across our footprint including the addition of approximately 33,000 residential customers ($7 million). These increases were partially offset by increased operating expenses ($6 million), higher bad debt expense ($5 million), higher depreciation and amortization expense ($12 million) and an increase in taxes ($5 million), primarily attributable to property taxes. Increased expense related to energy efficiency programs ($17 million) and increased expense related to higher gross receipt taxes ($26 million) were offset by a corresponding increase in the related revenues.

2012 Compared to 2011. Our Natural Gas Distribution business segment reported operating income of $226 million for each of 2012 and 2011. Operating income was unchanged despite substantially reduced revenues from near record mild temperatures in the first quarter of 2012 that were partially mitigated by weather hedges and weather normalization adjustments ($21 million), increased depreciation and amortization expense ($7 million) and increased property taxes ($4 million). These adverse impacts were offset by certain reduced operation and maintenance expenses ($5 million), lower bad debt expense ($7 million), the addition of over 22,000 customers ($6 million) and rate increases ($12 million). Decreased expense related to energy efficiency programs ($4 million) and decreased expense related to lower gross receipts taxes ($12 million) were offset by a corresponding reduction in the related revenues.

Energy Services

The following table provides summary data of our Energy Services business segment for 2013, 2012 and 2011 (in millions, except throughput and customer data):

	Year Ended December 31,		
	2013	2012	2011
Revenues	$ 2,401	$ 1,784	$ 2,511
Expenses:			
Natural gas	2,336	1,730	2,458
Operation and maintenance	46	45	41
Depreciation and amortization	5	6	5
Taxes other than income taxes	1	1	1
Goodwill impairment	—	252	—
Total expenses	2,388	2,034	2,505
Operating Income (Loss)	$ 13	$ (250)	$ 6
Throughput (in Bcf)	600	562	558
Number of customers at end of period (1)	17,510	16,330	14,267

(1) These numbers do not include approximately 8,800 and 12,700 natural gas customers as of December 31, 2013 and 2012, respectively, that are under residential and small commercial choice programs invoiced by their host utility.

2013 Compared to 2012. Our Energy Services business segment reported operating income of $13 million compared to $2 million for 2012, excluding the goodwill impairment charge discussed below. The increase in operating income of $11 million was primarily due to a $14 million positive impact from mark-to-market accounting for derivatives associated with certain natural gas purchases and sales used to lock in economic margins. A $2 million mark-to-market charge was incurred in 2013 compared to a charge of $16 million for 2012. Energy Services grew both volume and customers in 2013 offsetting the impact of the lower unit margin environment.

2012 Compared to 2011. Our Energy Services business segment reported operating income, excluding the goodwill impairment discussed below, of $2 million for 2012 compared to $6 million for 2011. The decrease in operating income of $4 million was primarily due to a $24 million negative impact of mark-to-market accounting for derivatives associated with certain forward natural gas purchases and sales used to lock in economic margins. 2012 included mark-to-market charges of $16 million compared to an $8 million benefit for the same period of 2011. Substantially offsetting this decrease was a $20 million improvement in operating margins primarily as a result of the termination of uneconomic transportation contracts and an increase in retail sales customers and volumes.

Goodwill Impairment

A non-cash goodwill impairment charge of $252 million for our Energy Services business segment was recorded in 2012. The adverse wholesale market conditions facing our energy services business, specifically the prospects for continued low geographic and seasonal price differentials for natural gas, led to a reduction in our estimate of the fair value of goodwill associated with this reporting unit.

Interstate Pipelines

The following table provides summary data of our Interstate Pipelines business segment for 2013, 2012 and 2011 (in millions, except throughput data):

	Year Ended December 31,		
	2013	2012	2011
Revenues	$ 186	$ 502	$ 553
Expenses:			
Natural gas	35	57	67
Operation and maintenance	51	153	152
Depreciation and amortization	20	56	54
Taxes other than income taxes	8	29	32
Total expenses	114	295	305
Operating Income	$ 72	$ 207	$ 248
Equity in earnings of unconsolidated affiliates	$ 7	$ 26	$ 21
Transportation throughput (in Bcf)	482	1,367	1,579

2013 Compared to 2012. Our Interstate Pipeline business segment reported operating income of $72 million for 2013 compared to $207 million for 2012. Substantially all of this segment was contributed to Enable on May 1, 2013. As a result, 2013 is not comparable to the prior year. Effective May 1, 2013, our equity method investment and related equity income in Enable are included in our Midstream Investments segment.

2012 Compared to 2011. Our Interstate Pipeline business segment reported operating income of $207 million for 2012 compared to $248 million for 2011. Operating income decreased $41 million primarily due to lower margins resulting from a backhaul contract that expired in 2011 ($16 million), as well as the associated reduction in compressor efficiency ($8 million) on the Carthage to Perryville pipeline due to lower volumes, lower off-system transportation revenues ($8 million), lower seasonal and market-sensitive transportation contracts ($7 million) and ancillary services ($7 million). These margin decreases were partially offset by the effects of the 10-year agreement with our natural gas distribution affiliate ($5 million) which we restructured in 2010. Operating income decreases due to higher operations and maintenance expenses ($1 million) and higher depreciation and amortization expenses ($2 million) due to asset additions were offset by lower taxes other than income taxes ($3 million).

Equity Earnings. This business segment recorded equity income of $7 million, $26 million and $21 million for the years ended December 31, 2013, 2012 and 2011, respectively, from its interest in Southeast Supply Header, LLC (SESH), a jointly-owned pipeline. The decrease from the year ended December 31, 2012 to the year ended December 31, 2013 was primarily due to the contribution of a 24.95% interest in SESH to Enable on May 1, 2013. Beginning May 1, 2013, equity earnings related to the interest in SESH contributed to Enable, as well as our remaining 25.05% interest in SESH, are reported as components of equity income in our Midstream Investments segment.

Field Services

The following table provides summary data of our Field Services business segment for 2013, 2012 and 2011 (in millions, except throughput data):

	Year Ended December 31,		
	2013	2012	2011
Revenues	$ 196	$ 506	$ 412
Expenses:			
Natural gas	54	122	68
Operation and maintenance	45	115	112
Depreciation and amortization	20	50	37
Taxes other than income taxes	4	5	6
Total expenses	123	292	223
Operating Income	$ 73	$ 214	$ 189
Equity in earnings of unconsolidated affiliates	$ —	$ 5	$ 9
Gathering throughput (in Bcf)	252	896	823

2013 Compared to 2012. Our Field Services business segment reported operating income of $73 million for 2013 compared to $214 million for 2012. Substantially all of this segment was contributed to Enable on May 1, 2013. As a result, 2013 is not comparable to the prior year. Effective May 1, 2013, our equity method investment and related equity income in Enable are included in our Midstream Investments segment.

2012 Compared to 2011. Our Field Services business segment reported operating income of $214 million for 2012 compared to $189 million for 2011. Operating income increased $25 million primarily from increased margins ($36 million) due to gathering projects in the Haynesville shale, including revenues from throughput guarantees, growth in gathering services and retained natural gas volumes, and acquisitions completed during 2012 ($13 million), partially offset by lower commodity prices ($28 million) on sales of retained natural gas. Operating income also increased ($3 million) due to the classification of earnings from the 50% partnership interest in Waskom which we already owned as operating income beginning in August 2012 instead of equity earnings as reported for prior periods, due to our July 31, 2012 purchase of the 50% interest in Waskom that we did not already own. Lower operation and maintenance expenses ($7 million) were partially offset by higher depreciation expense ($6 million).

Equity Earnings. This business segment recorded equity income of $-0-, $5 million and $9 million for the years ended December 31, 2013, 2012 and 2011, respectively, from its interest in Waskom. These amounts are included in Equity in earnings of unconsolidated affiliates under the Other Income (Expense) caption in the Statements of Consolidated Income. From August 1, 2012 through April 30, 2013, financial results for Waskom are included in operating income. On May 1, 2013, our 100% investment in Waskom was contributed to Enable.

Midstream Investments

During the eight months ended December 31, 2013, we reported pre-tax equity income of $173 million from our 58.3% limited partner interest in Enable and $8 million of pre-tax equity income from our 25.05% interest in SESH. Enable's gathering and processing operations in 2013 were positively impacted by increases in gross margin resulting from acquisitions, higher gathering and processing fixed-fee volumes, higher natural gas prices and increased processing margins, partially offset by a decline in customer volumes, a decline in NGL price spreads between Conway and Mont Belvieu, and the conversion of a processing contract from keep-whole to fixed-fee. Enable's transportation and storage operations in 2013 were adversely impacted by a decline in gross margins attributable to lower volumes, primarily due to lower price differentials, which negatively impacted margins on ancillary services, a reduction in liquid sales, a reduction to margins on off-system transportation revenues, a decline in interruptible transportation fees, and a reduction to storage demand fees.

Cash distributions received from Enable and SESH were approximately $106 million and $6 million, respectively, during the eight months ended December 31, 2013.

Enable Operating Data during the eight months ended December 31, 2013

	Eight Months Ended December 31, 2013
Natural gas gathered volumes - Trillion British Thermal Units per day (TBtu/d)	3.49
Natural gas transportation volumes - TBtu/d	4.58
Natural gas processed volumes - TBtu/d	1.45
Natural gas liquids sold - Gallons per day	2.61

Fluctuations in Commodity Prices and Derivative Instruments

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

LIQUIDITY AND CAPITAL RESOURCES

Our liquidity and capital requirements are affected primarily by our results of operations, capital expenditures, debt service requirements, tax payments, working capital needs, various regulatory actions and appeals relating to such actions. Our principal anticipated cash requirements for 2014 include capital expenditures of approximately $531 million.

We expect that anticipated 2014 cash needs will be met with borrowings under our credit facility, proceeds from commercial paper, anticipated cash flows from operations and distributions from Enable. Discretionary financing or refinancing may result in the issuance of debt securities in the capital markets or the arrangement of additional credit facilities. Issuances of debt in the capital markets, funds raised in the commercial paper markets and additional credit facilities may not, however, be available to us on acceptable terms.

The following table sets forth our capital expenditures for 2013 and estimates of our capital expenditures for currently identified and planned projects for 2014 through 2017 (in millions):

	2013	2014	2015	2016	2017	2018
Natural Gas Distribution	$ 430	$ 521	$ 491	$ 401	$ 421	$ 404
Energy Services	3	10	19	36	11	11
Interstate Pipelines	29	—	—	—	—	—
Field Services	16	—	—	—	—	—
Total	$ 478	$ 531	$ 510	$ 437	$ 432	$ 415

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

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

Contractual Obligations	Total	2014	2015-2016	2017-2018	2019 and thereafter
Long-term debt	$ 2,240	$ —	$ 325	$ 668	$ 1,247
Interest payments — long-term debt(1)	1,494	124	237	183	950
Short-term borrowings	43	43	—	—	—
Operating leases(2)	20	6	7	4	3
Benefit obligations(3)	—	—	—	—	—
Non-trading derivative liabilities	21	17	4	—	—
Other commodity commitments(4)	1,723	408	701	494	120
Total contractual cash obligations	$ 5,541	$ 598	$ 1,274	$ 1,349	$ 2,320

(1) We calculated estimated interest payments for long-term debt as follows: for fixed-rate debt and term debt, we calculated interest based on the applicable rates and payment dates; for variable-rate debt and/or non-term debt, we used interest rates

as of December 31, 2013. We expect to satisfy such interest payment obligations with cash flows from operations and short-term borrowings.

(2) For a discussion of operating leases, please read Note 13(c) to our consolidated financial statements.

(3) We expect to contribute approximately $7 million to our postretirement benefits plan in 2014 to fund a portion of our obligations in accordance with rate orders or to fund pay-as-you-go costs associated with the plan.

(4) For a discussion of other commodity commitments, please read Note 13(a) to our consolidated financial statements.

Off-Balance Sheet Arrangements

Prior to the distribution of CenterPoint Energy's ownership in Reliant Resources, Inc. (RRI) to its shareholders, we had guaranteed certain contractual obligations of what became RRI’s trading subsidiary. When the companies separated, RRI agreed to secure us against obligations under the guarantees RRI had been unable to extinguish by the time of separation. Pursuant to such agreement, as amended in December 2007, RRI (now GenOn Energy, Inc. (GenOn)) agreed to provide to us cash or letters of credit as security against our obligations under our remaining guarantees for demand charges under certain gas transportation agreements if and to the extent changes in market conditions expose us to a risk of loss on those guarantees based on an annual calculation, with any required collateral to be posted each December. The undiscounted maximum potential payout of the demand charges under these transportation contracts, which will be in effect until 2018, was approximately $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, we could have to honor our guarantee and, in such event, any collateral provided as security may be insufficient to satisfy our obligations.

CERC Corp. has also provided a guarantee of collection of Enable's obligations under its $1.05 billion three-year unsecured term loan facility, which guarantee is subordinated to all senior debt of CERC Corp.

As of December 31, 2013, no amounts have been recorded related to the guarantees discussed above in the Consolidated Balance Sheets. Other than the guarantees discussed above and operating leases, we have no off-balance sheet arrangements.

Regulatory Matters

Gas Operations

City of Houston Settlement. In January 2013, the City of Houston initiated a rate proceeding against our natural gas distribution business (Gas Operations) claiming regulatory disclosures indicated that Gas Operations was earning more on an annual basis than authorized. In February 2014, Gas Operations and City of Houston agreed (i) to terminate the rate proceeding, and (ii) that Gas Operations would not seek a base rate increase before Fall 2016.

Houston and South Texas Gas Reliability Infrastructure Programs (GRIP). Gas Operations' Houston and South Texas Divisions each submitted annual GRIP filings on March 28, 2013. For the Houston Division, the filing was to recover costs related to $55.8 million in incremental capital expenditures that were incurred in 2012. The increase in revenue requirements for this filing period is $10.7 million annually based on an authorized rate of return of 8.65%. For the South Texas Division, the filing was to recover costs related to $17.5 million in incremental capital expenditures that were incurred in 2012. The increase in revenue requirements for this filing period is $2.9 million annually based on an authorized rate of return of 8.75%. Rates were completely implemented by July 2013.

Arkansas Billing Determinant Rate Adjustment Tariff (BDA) Filing. Gas Operations’ Arkansas Division made its annual BDA filing with the Arkansas Public Service Commission (APSC) on March 27, 2013 to request recovery of a calendar year 2012 shortfall of $6.8 million. No exceptions were noted by the APSC staff and the revised rates went into effect on June 1, 2013.

Mississippi Rate Regulation Adjustment Rider (RRA). Gas Operations’ Mississippi Division submitted an annual RRA filing with the Mississippi Public Service Commission (MPSC) on May 1, 2013 to request recovery of a calendar year 2012 earnings shortfall of approximately $3.2 million. The MPSC approved approximately $2.9 million, and the revised rates went into effect in July 2013.

Cost of Service Adjustment (COSA) Rate Adjustments. In March 2008, Gas Operations filed a request to change its rates with the Railroad Commission of Texas (Railroad Commission) and the 47 cities in its Texas Coast service territory, including a request for an annual cost of service adjustment mechanism, or COSA, that adjusts rates annually for changes in invested capital as well as certain operating expenses. In 2008, the Railroad Commission approved the implementation of rates increasing annual revenues from the Texas Coast service territory by approximately $3.5 million. The approved rates were contested by a coalition of nine cities in an appeal to the 353rd district court in Travis County, Texas. In 2010, the district court ruled that the Railroad Commission lacked authority to impose the approved COSA mechanism both in those nine cities and in those areas in which the Railroad Commission has original jurisdiction. The decision by the District Court placed at risk certain revenues collected pursuant to COSA mechanisms. The Railroad Commission and Gas Operations appealed the court's ruling on the COSA mechanism. In January 2014, the Texas Supreme Court confirmed that the Railroad Commission had authority to approve the COSA rate adjustments utilized by Gas Operations and remanded the case back to state district court.

Minneapolis Franchise. Gas Operations currently provides natural gas distribution services to approximately 124,000 customers in Minneapolis, Minnesota under a franchise that is due to expire at the end of 2014. In June 2013, the Minneapolis City Council (City Council) voted to hold public hearings on August 1, 2013 to consider (i) authorizing the establishment of a municipal electric utility and authorizing the city to own, operate, construct and extend electric facilities and acquire the property of any existing electric public utility operating within Minneapolis, and (ii) authorizing the establishment of a municipal gas utility and authorizing the city to own, operate, construct and extend gas and similar facilities and acquire the property of any existing gas public utility operating within Minneapolis. On August 16, 2013, the City Council voted not to conduct a special election on the question of whether the city should be authorized to establish a municipal utility. Additionally, the City Council directed city staff to begin negotiations with Gas Operations on a franchise renewal and to work to complete the franchise agreement by June 2014.

Minnesota Rate Proceeding. On August 2, 2013, Gas Operations filed a general rate case in Minnesota to increase overall revenue $44.3 million annually, based on a rate base of $700 million and return on equity (ROE) of 10.3%. In compliance with state law, Gas Operations implemented interim rates reflecting $42.9 million dollars of the requested increase for gas used on and after October 1, 2013. Evidentiary hearings were held before an Administrative Law Judge in January 2014, and Gas Operations expects a final decision from the Minnesota Public Utilities Commission in its rate proceeding in mid-summer 2014. This rate filing is intended to recover significant capital expenditures Gas Operations is making in Minnesota and includes moving $15.0 million of energy efficiency expenditures into base rates.

Enable Midstream Partners

In August 2012, MRT, a subsidiary of Enable and an interstate pipeline that provides natural gas transportation, natural gas storage and pipeline services to customers principally in Arkansas, Illinois and Missouri, made a rate filing with the Federal Energy Regulatory Commission (FERC) pursuant to Section 4 of the Natural Gas Act. In its filing, MRT requested an annual cost of service of $104 million (an increase of approximately $48 million above the annual cost of service underlying the current FERC approved maximum rates for MRT's pipeline), new depreciation rates, an overall rate of return of 10.813% (based on a ROE of 13.62%), a regulatory compliance cost (RCC) surcharge with a true-up mechanism to recover safety, environmental, and security costs associated with mandated requirements and billing determinants reflecting no adjustments for MRT's conversion of a portion of EGT's firm capacity to a lease. On July 30, 2013, MRT filed with the FERC an uncontested Stipulation and Agreement and Offer of Settlement, resolving all issues in the rate case. In particular, MRT withdrew its proposed RCC surcharge. The settlement specifies few particulars, other than setting an annual overall cost-of-service for MRT of $84.0 million and increasing the depreciation rates for certain asset classes. In September 2013, the FERC approved the settlement. Although the settlement became effective November 1, 2013, the settlement rates are effective as of March 1, 2013. As a result, in the fourth quarter of 2013, MRT made refunds to certain of its customers totaling approximately $5.9 million, which had previously been reserved.

Other Matters

Credit Facility

As of February 14, 2014, we had the following revolving credit facility (in millions):

Date Executed	Size of Facility	Amount Utilized at February 14, 2013	Termination Date
September 9, 2011	$ 600	$ —	September 9, 2018

CERC Corp.'s $600 million revolving credit facility can be drawn at the London Interbank Offered Rate (LIBOR) plus 150 basis points based on CERC Corp.'s current credit ratings. The revolving credit facility contains a financial covenant which limits our consolidated debt to an amount not to exceed 65% of our consolidated capitalization.

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

On April 11, 2013, we amended our revolving credit facility to add exceptions to the covenants which restrict (i) the consolidation, merger or disposal of assets and (ii) the sale of stock in certain significant subsidiaries, in each case to permit the transactions contemplated in the formation of Enable.

On September 9, 2013, our revolving credit facility was amended to, among other things, (i) reduce the size of the facility from $950 million to $600 million and (ii) extend the scheduled termination date of the facility from September 9, 2016 to September 9, 2018.

CERC Corp.'s $600 million revolving credit facility backstops its $600 million commercial paper program. As of December 31, 2013, CERC Corp. had $118 million of outstanding commercial paper.

Securities Registered with the SEC

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

Temporary Investments

As of February 14, 2014, we had external temporary investments in a money market fund of $104 million.

Money Pool

We participate in a money pool through which we and certain of our affiliates can borrow or invest on a short-term basis. Funding needs are aggregated and external borrowing or investing is based on the net cash position. The net funding requirements of the money pool are expected to be met with borrowings by CenterPoint Energy under its revolving credit facility or the sale by CenterPoint Energy of its commercial paper. At February 14, 2014, we had an investment of $98 million in the money pool. The money pool may not provide sufficient funds to meet our cash needs.

Impact on Liquidity of a Downgrade in Credit Ratings

The interest on borrowings under our credit facilities is based on our credit rating. As of February 14, 2014, Moody’s Investors Service, Inc. (Moody’s), Standard & Poor’s Rating Services (S&P), a division of The McGraw-Hill Companies, and Fitch, Inc. (Fitch) had assigned the following credit ratings to our senior unsecured debt:

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

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

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

(3) A Fitch rating outlook encompasses a one-to-two year horizon as to the likely ratings direction.

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

A decline in credit ratings could increase borrowing costs under our $600 million revolving credit facility. If our credit ratings had been downgraded one notch by each of the three principal credit rating agencies from the ratings that existed at December 31, 2013, the impact on the borrowing costs under our credit facility would have been immaterial. A decline in credit ratings would also increase the interest rate on long-term debt to be issued in the capital markets and could negatively impact our ability to complete capital market transactions and to access the commercial paper market. Additionally, a decline in credit ratings could increase cash collateral requirements and reduce earnings of our Natural Gas Distribution and Energy Services business segments.

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

CenterPoint Energy Services, Inc. (CES), our wholly owned subsidiary operating in our Energy Services business segment, provides comprehensive natural gas sales and services primarily to commercial and industrial customers and electric and gas utilities throughout the central and eastern United States. In order to economically hedge its exposure to natural gas prices, CES uses derivatives with provisions standard for the industry, including those pertaining to credit thresholds. Typically, the credit threshold negotiated with each counterparty defines the amount of unsecured credit that such counterparty will extend to CES. To the extent that the credit exposure that a counterparty has to CES at a particular time does not exceed that credit threshold, CES is not obligated to provide collateral. Mark-to-market exposure in excess of the credit threshold is routinely collateralized by CES. As of December 31, 2013, the amount posted as collateral aggregated approximately $5 million. Should the credit ratings of CERC Corp. (as the credit support provider for CES) fall below certain levels, CES would be required to provide additional collateral up to the amount of its previously unsecured credit limit. We estimate that as of December 31, 2013, unsecured credit limits extended to CES by counterparties aggregate $308 million and $1 million of such amount was utilized.

Pipeline tariffs and contracts typically provide that if the credit ratings of a shipper or the shipper’s guarantor drop below a threshold level, which is generally investment grade ratings from both Moody’s and S&P, cash or other collateral may be demanded from the shipper in an amount equal to the sum of three months’ charges for pipeline services plus the unrecouped cost of any lateral built for such shipper. If the credit ratings of CERC Corp. decline below the applicable threshold levels, CERC Corp. might need to provide cash or other collateral of as much as $180 million as of December 31, 2013. The amount of collateral will depend on seasonal variations in transportation levels.

Cross Defaults

Under CenterPoint Energy's revolving credit facility, a payment default on, or a non-payment default that permits acceleration of, any indebtedness exceeding $75 million by us will cause a default. In addition, three outstanding series of CenterPoint Energy's senior notes, aggregating $750 million in principal amount as of December 31, 2013, provide that a payment default by us in respect of, or an acceleration of, borrowed money and certain other specified types of obligations, in the aggregate principal amount of $50 million, will cause a default. A default by CenterPoint Energy would not trigger a default under our debt instruments or revolving credit facility.

Possible Acquisitions, Divestitures and Joint Ventures

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

Enable Midstream Partners

In connection with its formation on May 1, 2013, Enable (i) entered into a $1.05 billion 3-year senior unsecured term loan facility, (ii) repaid $1.05 billion of indebtedness owed to CERC Corp., and (iii) entered into a $1.4 billion senior unsecured revolving credit facility. Enable's $1.4 billion senior unsecured revolving credit facility backstops its $1.4 billion commercial paper program.

As of January 31, 2014, Enable had no outstanding commercial paper and $318 million borrowed under its revolving credit facility. Any reduction in Enable's credit ratings could prevent it from accessing the commercial paper markets.

The sponsors of Enable, including us, may from time to time provide funds to Enable through loans and/or capital contributions in addition to funds that Enable may obtain from time to time under its revolving credit facility, commercial paper program or from other sources, which loans or capital contributions could be substantial.

Certain of the entities contributed to Enable by CERC Corp. are obligated on approximately $363 million of indebtedness owed to a wholly owned subsidiary of CERC Corp. that is scheduled to mature in 2017.

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. In July 2013, CERC Corp. received a cash distribution of approximately $36 million from Enable made with respect to CERC Corp.'s limited partner interest in Enable for the months of May and June 2013 (the two months in the second quarter following the formation of Enable on May 1, 2013). In November 2013, CERC Corp. received a cash distribution of approximately $70 million from Enable made with respect to CERC Corp.'s limited partner interest in Enable for the third quarter of 2013. CERC Corp. received a cash distribution of approximately $64 million from Enable in February 2014 made with respect to CERC Corp.'s limited partner interest in Enable for the fourth quarter of 2013.

Under the terms of an omnibus agreement entered into in connection with the formation of Enable, CenterPoint Energy and OGE Energy are obligated to indemnify Enable for specified breaches of representations and warranties in the master formation agreement pursuant to which Enable was formed related to: (i) their respective authority to enter into the transactions that formed Enable and the capitalization of the entities contributed to Enable; (ii) permits related to the operation of the assets contributed to Enable; (iii) compliance with environmental laws; (iv) title to properties and rights of way; (v) the tax classification of the entities contributed to Enable; (vi) indemnified taxes; and (vii) events and conditions associated with CenterPoint Energy and OGE's respective ownership and operation of the assets contributed to Enable. Pursuant to the terms of the omnibus agreement, each of CenterPoint Energy's and OGE's respective maximum liability for this indemnification obligation with respect to permit, environmental and title representations will not exceed $250 million, and neither OGE Energy nor CenterPoint Energy will have any obligation under this indemnification until Enable's aggregate indemnifiable losses exceed $25 million, respectively. CenterPoint Energy's and OGE Energy's indemnification obligations under the omnibus agreement will survive (i) for permit matters until May 1, 2014, (ii) for environmental and title and rights of way matters until May 1, 2016 and (iii) for tax classification matters and indemnified taxes until 30 days following the expiration of the applicable statute of limitations. Indemnification obligations for authority and capitalization matters survive indefinitely.

Dodd-Frank Swaps Regulation

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

Other Factors that Could Affect Cash Requirements

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

- cash collateral requirements that could exist in connection with certain contracts, including our weather hedging arrangements, and gas purchases, gas price and gas storage activities of our Natural Gas Distribution and Energy Services business segments;

- acceleration of payment dates on certain gas supply contracts under certain circumstances, as a result of increased gas prices and concentration of natural gas suppliers;

- increased costs related to the acquisition of natural gas;
- increases in interest expense in connection with debt refinancings and borrowings under credit facilities;
- various legislative or regulatory actions;
- incremental collateral, if any, that may be required due to regulation of derivatives;
- the ability of GenOn and its subsidiaries to satisfy their obligations in respect of GenOn's indemnity obligations to CenterPoint Energy and its subsidiaries or in connection with the contractual obligations to a third party pursuant to which we are their guarantor;
- delays in cash collections attributable to billing delays;
- slower customer payments and increased write-offs of receivables due to higher gas prices or changing economic conditions;
- the outcome of litigation brought by and against us;
- restoration costs and revenue losses resulting from future natural disasters such as hurricanes and the timing of recovery of such restoration costs; and
- various other risks identified in "Risk Factors" in Item 1A of this report.

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

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

Relationship with CenterPoint Energy

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

CRITICAL ACCOUNTING POLICIES

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

Accounting for Rate Regulation

Accounting guidance for regulated operations provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. Our Natural Gas Distribution business segment applies this accounting guidance. Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet as regulatory assets or liabilities and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and the strength or status of applications for rehearing or state court appeals. If events were to occur that would make the recovery of these assets and liabilities no longer probable, we would be required to write off or write down these regulatory assets and liabilities. At December 31, 2013, we had recorded regulatory assets of $100 million and regulatory liabilities of $642 million.

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

We review the carrying value of our long-lived assets, including identifiable intangibles, goodwill and equity method investments whenever events or changes in circumstances indicate that such carrying values may not be recoverable, and at least annually for goodwill as required by accounting guidance for goodwill and other intangible assets. A loss in value of an equity method investment is recognized when the decline is deemed to be other than temporary. Unforeseen events and changes in market conditions could have a material effect on the value of long-lived assets, intangibles, goodwill and equity method investments due to changes in estimates of future cash flows, interest rate and regulatory matters and could result in an impairment charge. We recorded goodwill impairment of $-0-, $252 million and $-0- during 2013, 2012 and 2011. We did not record material impairments to long-lived assets, including intangibles, or equity method investments during 2013, 2012, and 2011.

We performed our annual goodwill impairment test in the third quarter of 2013 and determined, based on the results of the first step, using the income approach, no impairment charge was required for any reporting unit. Our reporting units approximate our reportable segments.

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

The determination of fair value requires significant assumptions by management which are subjective and forward-looking in nature. To assist in making these assumptions, we utilized a third-party valuation specialist in both determining and testing key assumptions used in the valuation of each of our reporting units. We based our assumptions on projected financial information that we believe is reasonable; however, actual results may differ materially from those projections. These projected cash flows factor in planned growth initiatives, and for our Natural Gas Distribution reporting unit, the regulatory environment. The fair value of our Natural Gas Distribution and Energy Services reporting units exceeded the carrying value by approximately $2.3 billion and $259 million, respectively, or approximately 80% and 50%, excess fair value over the carrying values for each reporting unit, respectively. A key assumption in the income approach was the weighted average cost of capital of 5.1% and 6.0% applied in the valuation for Natural Gas Distributions and Energy Services, respectively.

Although there was not a goodwill asset impairment in our 2013 annual test, an interim impairment test could be triggered by the following: actual earnings results that are materially lower than expected, significant adverse changes in the operating environment, an increase in the discount rate, changes in other key assumptions which require judgment and are forward looking in nature, or if our market capitalization falls below book value for an extended period of time. No impairment triggers were identified subsequent to our 2013 annual test.

Unbilled Energy Revenues

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

NEW ACCOUNTING PRONOUNCEMENTS

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

OTHER SIGNIFICANT MATTERS

Pension Plans. As discussed in Note 6(a) to our consolidated financial statements, we participate in CenterPoint Energy's qualified and non-qualified pension plans covering substantially all employees. The expected pension cost for 2014 is $29 million, of which we expect $23 million to impact pre-tax earnings, based on an expected return on plan assets of 7.00% and a discount rate of 4.80% as of December 31, 2013. We recorded pension expense of $31 million for the year ended December 31, 2013. Future changes in plan asset returns, assumed discount rates and various other factors related to the pension plans will impact our future pension expense. We cannot predict with certainty what these factors will be in the future.

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

Impact of Changes in Interest Rates and Energy Commodity Prices

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

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

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

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

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

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

Interest Rate Risk

As of December 31, 2013, we had outstanding long-term debt and borrowings from affiliates that subject us to the risk of loss associated with movements in market interest rates.

Our floating-rate obligations aggregated $156 million and $779 million at December 31, 2013 and 2012, respectively. If the floating interest rates were to increase by 10% from December 31, 2013 rates, our combined interest expense would increase by less than $1 million annually.

As of December 31, 2013 and 2012, we had outstanding fixed-rate debt aggregating $2.2 billion and $2.7 billion, respectively, in principal amount and having a fair value of $2.4 billion and $3.1 billion, respectively. Because these instruments are fixed-rate, they do not expose us to the risk of loss in earnings due to changes in market interest rates (please read Note 11 to our consolidated financial statements). However, the fair value of these instruments would increase by approximately $81 million if interest rates were to decline by 10% from their levels at December 31, 2013. In general, such an increase in fair value would impact earnings and cash flows only if we were to reacquire all or a portion of these instruments in the open market prior to their maturity.

Commodity Price Risk From Non-Trading Activities

We use derivative instruments as economic hedges to offset the commodity price exposure inherent in our businesses. The stand-alone commodity risk created by these instruments, without regard to the offsetting effect of the underlying exposure these instruments are intended to hedge, is described below. We measure the commodity risk of our non-trading energy derivatives using a sensitivity analysis. The sensitivity analysis performed on our non-trading energy derivatives measures the potential loss in fair value based on a hypothetical 10% movement in energy prices. At December 31, 2013, the recorded fair value of our non-trading energy derivatives was a net asset of $13 million (before collateral), all of which is related to our Energy Services business segment. An increase of 10% in the market prices of energy commodities from their December 31, 2013 levels would have decreased the fair value of our non-trading energy derivatives net asset by $4 million.

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of CenterPoint Energy Resources Corp. and subsidiaries (the "Company", an indirect wholly owned subsidiary of CenterPoint Energy, Inc.) as of December 31, 2013 and 2012, and the related statements of consolidated income, comprehensive income, stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of CenterPoint Energy Resources Corp. and subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 12, 2014

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

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

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

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

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control — Integrated Framework* (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control — Integrated Framework* (1992), our management has concluded that our internal control over financial reporting was effective as of December 31, 2013.

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

/s/ SCOTT M. PROCHAZKA

President and Chief Executive Officer

/s/ GARY L. WHITLOCK

Executive Vice President and Chief Financial Officer

March 12, 2014

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

STATEMENTS OF CONSOLIDATED INCOME

	Year Ended December 31,		
	2013	2012	2011
	(in millions)		
Revenues	$ 5,522	$ 4,901	$ 6,102
Expenses:			
Natural gas	3,908	2,873	4,055
Operation and maintenance	828	951	964
Depreciation and amortization	230	285	262
Taxes other than income taxes	155	146	159
Goodwill impairment	—	252	—
Total	5,121	4,507	5,440
Operating Income	401	394	662
Other Income (Expense):			
Interest and other finance charges	(154)	(179)	(190)
Equity in earnings of unconsolidated affiliates	188	31	30
Step acquisition gain	—	136	—
Other, net	—	1	1
Total	34	(11)	(159)
Income Before Income Taxes	435	383	503
Income tax expense	371	246	187
Net Income	$ 64	$ 137	$ 316

See Notes to Consolidated Financial Statements

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

STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME

	Year Ended December 31,		
	2013	2012	2011
	(in millions)		
Net income	$ 64	$ 137	$ 316
Other comprehensive income (loss), net of tax:			
Adjustment to postretirement and other postemployment plans (net of tax of $6, $5 and $1)	6	6	(2)
Other comprehensive income (loss)	6	6	(2)
Comprehensive income	$ 70	$ 143	$ 314

See Notes to Consolidated Financial Statements

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

CONSOLIDATED BALANCE SHEETS

	December 31, 2013	December 31, 2012
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1	$ 1
Accounts receivable, net	565	544
Accrued unbilled revenue	311	258
Accounts and notes receivable — affiliated companies	44	15
Inventory	179	228
Non-trading derivative assets	24	36
Taxes receivable	18	—
Deferred income tax assets	21	—
Prepaid expenses and other current assets	51	133
Total current assets	1,214	1,215
Property, Plant and Equipment, Net	3,436	7,901
Other Assets:		
Goodwill	840	1,468
Non-trading derivative assets	10	6
Notes receivable — affiliated companies	363	—
Investment in unconsolidated affiliates	4,518	405
Other	161	195
Total other assets	5,892	2,074
Total Assets	$ 10,542	$ 11,190
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current Liabilities:		
Short-term borrowings	$ 43	$ 38
Current portion of long-term debt	—	365
Accounts payable	495	443
Accounts and notes payable — affiliated companies	103	818
Taxes accrued	74	72
Interest accrued	36	48
Customer deposits	78	79
Non-trading derivative liabilities	17	14
Other	163	177
Total current liabilities	1,009	2,054
Other Liabilities:		
Accumulated deferred income taxes, net	2,082	1,676
Non-trading derivative liabilities	4	2
Benefit obligations	102	122
Regulatory liabilities	642	619
Other	160	208
Total other liabilities	2,990	2,627
Long-Term Debt	2,240	2,276
Commitments and Contingencies (Note 13)		
Stockholder's Equity	4,303	4,233
Total Liabilities And Stockholder's Equity	$ 10,542	$ 11,190

See Notes to Consolidated Financial Statements

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

STATEMENTS OF CONSOLIDATED CASH FLOWS

	Year Ended December 31,		
	2013	2012	2011
		(in millions)	
Cash Flows from Operating Activities:			
Net income	$ 64	$ 137	$ 316
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	230	285	262
Amortization of deferred financing costs	11	13	13
Deferred income taxes	357	245	144
Goodwill impairment	—	252	—
Step acquisition gain	—	(136)	—
Write-down of natural gas inventory	4	4	11
Equity in earnings of unconsolidated affiliates, net of distributions	(58)	8	8
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues, net	(220)	6	67
Accounts receivable/payable, affiliates	(2)	5	(14)
Inventory	(10)	41	20
Taxes receivable	(18)	1	62
Accounts payable	110	2	(101)
Fuel cost recovery	108	(52)	(70)
Interest and taxes accrued	33	(11)	6
Non-trading derivatives, net	4	19	(10)
Margin deposits, net	16	53	34
Other current assets	3	(10)	11
Other current liabilities	5	8	(12)
Other assets	(18)	(13)	(3)
Other liabilities	6	(28)	22
Other, net	10	7	3
Net cash provided by operating activities	635	836	769
Cash Flows from Investing Activities:			
Capital expenditures, net of acquisitions	(495)	(566)	(644)
Acquisitions, net of cash acquired	—	(360)	—
Investment in unconsolidated affiliates	—	(5)	(12)
Cash contribution to Enable	(38)	—	—
Other, net	(3)	8	10
Net cash used in investing activities	(536)	(923)	(646)
Cash Flows from Financing Activities:			
Increase (decrease) in short-term borrowings, net	5	(24)	9
Proceeds from (payments of) commercial paper, net	118	(285)	102
Proceeds from long-term debt	1,050	—	550
Payments of long-term debt	(525)	—	(606)
Cash paid for debt exchange	(5)	—	(58)
Debt issuance costs	(1)	—	(14)
Increase (decrease) in notes payable to affiliates	(741)	396	(106)
Net cash provided by (used in) financing activities	(99)	87	(123)
Net Decrease in Cash and Cash Equivalents	—	—	—
Cash and Cash Equivalents at Beginning of the Year	1	1	1
Cash and Cash Equivalents at End of the Year	$ 1	$ 1	$ 1
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest, net of capitalized interest	$ 148	$ 163	$ 177
Income taxes (refunds), net	(5)	3	(20)
Non-cash transactions:			
Accounts payable related to capital expenditures	$ 21	$ 60	$ 53
Formation of Enable	4,252	—	—

See Notes to Consolidated Financial Statements

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

STATEMENTS OF CONSOLIDATED STOCKHOLDER'S EQUITY

	2013		2012		2011	
	Shares	Amount	Shares	Amount	Shares	Amount
			(in millions, except share amounts)			
Common Stock						
Balance, beginning of year	1,000	$ —	1,000	$ —	1,000	$ —
Balance, end of year	1,000	—	1,000	—	1,000	—
Additional Paid-in-Capital						
Balance, beginning of year		2,416		2,416		2,416
Balance, end of year		2,416		2,416		2,416
Retained Earnings						
Balance, beginning of year		1,818		1,681		1,365
Net income		64		137		316
Balance, end of year		1,882		1,818		1,681
Accumulated Other Comprehensive Loss						
Balance, end of year:						
Adjustment to postretirement and other postemployment plans		5		(1)		(7)
Total accumulated other comprehensive loss, end of year		5		(1)		(7)
Total Stockholder's Equity		$ 4,303		$ 4,233		$ 4,090

See Notes to Consolidated Financial Statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Background

CenterPoint Energy Resources Corp. (CERC Corp. and, together with its subsidiaries, CERC), which owns and operates natural gas distribution systems 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 in 21 states. 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.

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

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

(2) Summary of Significant Accounting Policies

(a) Use of Estimates

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

(b) Principles of Consolidation

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

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. In connection with the closing (i) CERC Corp. converted its direct wholly owned subsidiary, CenterPoint Energy Field Services, LLC, a Delaware limited liability company (CEFS), into a Delaware limited partnership that became Enable, (ii) CERC Corp. contributed to Enable its equity interests in each of CenterPoint Energy Gas Transmission Company, LLC, which has been subsequently renamed Enable Gas Transmission, LLC (EGT), CenterPoint Energy - Mississippi River Transmission, LLC, which has been subsequently renamed Enable Mississippi River Transmission, LLC (MRT), certain of its other midstream subsidiaries (Other CNP Midstream Subsidiaries), and a 24.95% interest in Southeast Supply Header, LLC (SESH and, collectively with CEFS, EGT, MRT and Other CNP Midstream Subsidiaries, CenterPoint Midstream), and (iii) OGE and ArcLight indirectly contributed 100% of the equity interests in Enogex LLC, which has been subsequently renamed Enable Oklahoma Intrastate Transmission, LLC (Enogex), to Enable.

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. The general partner of Enable is currently governed by a board of directors made up of an equal number of representatives designated by each of CERC Corp. and OGE. The investment in Enable is accounted for utilizing the equity method of accounting. As of December 31, 2013, CERC determined that Enable was a variable interest entity (VIE); however, CERC is not the primary beneficiary and as such, this entity is not consolidated.

Prior to July 2012, CERC owned a 50% interest in Waskom Gas Processing Company (Waskom), a Texas general partnership, which owns and operates a natural gas processing plant and natural gas gathering assets. On July 31, 2012, CERC purchased the

50% interest that it did not already own in Waskom, as well as other gathering and related assets from a third-party for approximately $273 million. The amount of the purchase price allocated to the acquisition of the 50% interest in Waskom was approximately $201 million, with the remaining purchase price allocated to the other gathering assets, based on a discounted cash flow methodology. The $273 million purchase price was allocated as follows: $253 million to property, plant and equipment; $16 million to goodwill; and the remaining balance to other assets and liabilities. The purchase of the 50% interest in Waskom was determined to be a business combination achieved in stages, and as such CERC recorded a pre-tax gain of approximately $136 million on July 31, 2012, which is the result of remeasuring CERC's original 50% interest in Waskom to fair value. As a result of the purchase, CERC recorded goodwill of $24 million, which includes $17 million related to Waskom (including the re-measurement of its existing 50% interest) and $7 million related to the other gathering and related assets.

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

(c) Revenues

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

(d) Long-lived Assets and Intangibles

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

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

(e) Regulatory Assets and Liabilities

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

CERC’s rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. As of both December 31, 2013 and 2012, these removal costs of $593 million and $573 million are classified as regulatory liabilities in the Consolidated Balance Sheets. In addition, a portion of the amount of removal costs that relate to asset retirement obligations has been reclassified from a regulatory liability to an asset retirement liability in accordance with accounting guidance for conditional asset retirement obligations.

(f) Depreciation and Amortization Expense

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

(g) Capitalization of Interest and Allowance for Funds Used During Construction

Interest and allowance for funds used during construction (AFUDC) are capitalized as a component of projects under construction and are amortized over the assets’ estimated useful lives once the assets are placed in service. AFUDC represents the composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction for subsidiaries that apply the guidance for accounting for regulated operations. During 2013, 2012 and 2011, CERC capitalized interest and AFUDC of $1 million, $2 million and less than $1 million, respectively.

(h) Income Taxes

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

(i) Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount and do not bear interest. It is the policy of management to review the outstanding accounts receivable monthly, as well as the bad debt write-offs experienced in the past, and establish an allowance for doubtful accounts. Account balances are charged off against the allowance when management determines it is probable the receivable will not be recovered. Accounts receivable are net of an allowance for doubtful accounts of $25 million and $23 million at December 31, 2013 and 2012, respectively. The provision for doubtful accounts in CERC's Statements of Consolidated Income for 2013, 2012 and 2011 was $20 million, $15 million and $25 million, respectively.

(j) Inventory

Inventory consists principally of materials and supplies and natural gas. Materials and supplies are valued at the lower of average cost or market. Materials and supplies are recorded to inventory when purchased and subsequently charged to expense or capitalized to plant when installed. Natural gas inventories of CERC's Energy Services business segment are also primarily valued at the lower of average cost or market. Natural gas inventories of CERC's Natural Gas Distribution business segment are primarily valued at weighted average cost. During 2013, 2012 and 2011, CERC recorded $4 million, $4 million and $11 million, respectively, in write-downs of natural gas inventory to the lower of average cost or market.

	December 31,	
	2013	2012
	(in millions)	
Materials and supplies	$ 34	$ 83
Natural gas	145	145
Total inventory	$ 179	$ 228

(k) Derivative Instruments

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

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

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

(l) Environmental Costs

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

(m) Statements of Consolidated Cash Flows

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

(n) New Accounting Pronouncements

In February 2013, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2013-02, "Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income" (ASU 2013-02). The objective of ASU 2013-02 is to improve the transparency of changes in other comprehensive income and items reclassified out of Accumulated Other Comprehensive Income in financial statements. This new guidance is effective for a reporting entity's first reporting period beginning after December 15, 2012 and should be applied prospectively. CERC's adoption of this new guidance on January 1, 2013 did not have a material impact on its financial position, results of operations or cash flows.

In December 2011 and January 2013, the FASB issued Accounting Standards Update No. 2011-11, "Disclosures About Offsetting Assets and Liabilities" (ASU 2011-11) and No. 2013-01, "Clarifying the Scope of Disclosures About Offsetting Assets and Liabilities" (ASU 2013-01), respectively. The objective of ASU 2011-11 is to enhance disclosures about the nature of an entity's rights of setoff and related arrangements associated with its financial instruments and derivative instruments. The objective of ASU 2013-01 is to clarify which instruments and transactions are subject to ASU 2011-11. Both ASU 2011-11 and ASU 2013-01 are effective for a reporting entity's first reporting period beginning on or after January 1, 2013 and should be applied retrospectively. CERC's adoption of this new guidance on January 1, 2013 did not have a material impact on its financial position, results of operations or cash flows.

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

(o) Other Current Assets and Liabilities

Included in other current assets on the Consolidated Balance Sheets at December 31, 2013 and 2012 were $4 million and $12 million, respectively, of margin deposits and $22 million and $86 million, respectively of under-recovered gas cost. Included in other current liabilities on the Consolidated Balance Sheets at December 31, 2013 and 2012 were $42 million and $6 million, respectively, of over-recovered gas cost.

(3) Property, Plant and Equipment

(a) Property, Plant and Equipment

Property, plant and equipment includes the following:

	Weighted Average Useful Lives (Years)	December 31, 2013		December 31, 2012
		(in millions)		
Natural Gas Distribution	31	$ 4,694		$ 4,321
Energy Services	26	82		80
Interstate Pipelines	—	—	(1)	2,803
Field Services	—	—	(1)	2,359
Other property	13	39		52
Total		4,815		9,615
Accumulated depreciation and amortization:				
Natural Gas Distribution		1,324		1,194
Energy Services		28		25
Interstate Pipelines		—		355
Field Services		—		118
Other property		27		22
Total accumulated depreciation and amortization		1,379		1,714
Property, plant and equipment, net		$ 3,436		$ 7,901

(1) Following the formation of Enable on May 1, 2013, substantially all of the assets of CERC's former Interstate Pipelines and Field Services business segments are owned by Enable.

(b) Depreciation and Amortization

The following table presents depreciation and amortization expense for 2013, 2012 and 2011:

	Year Ended December 31, 2013	2012	2011
	(in millions)		
Depreciation expense	$ 218	$ 267	$ 244
Amortization expense	12	18	18
Total depreciation and amortization expense	$ 230	$ 285	$ 262

(c) Asset Retirement Obligations

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

	December 31, 2013	December 31, 2012
Beginning balance	$ 135	$ 132
Accretion expense	4	6
Revisions in estimates of cash flows	(38)	(3)
Ending balance	$ 101	$ 135

The decrease of $38 million in the ARO from the revision of estimate in 2013 is primarily attributable to a decrease in the future expected cash flows associated with the retirement of steel pipe. The decrease of $3 million in the ARO from the revision of estimate in 2012 is primarily attributable to a steel pipe replacement effort during 2012 which shifted the cost of removal obligation further into the future and lowered the current liability. There were no material additions or settlements during the years ended December 31, 2013 or 2012.

(4) Goodwill

Goodwill by reportable business segment and changes in the carrying amount of goodwill are as follows (in millions):

	December 31, 2011	Impairment Charge	Waskom Acquisition (1)	December 31, 2012	Contributed to Enable (1)	December 31, 2013
Natural Gas Distribution	$ 746	$ —	$ —	$ 746	$ —	$ 746
Interstate Pipelines	579	—	—	579	579	—
Energy Services	335	252	—	83	—	83
Field Services	25	—	24	49	49	—
Other	11	—	—	11	—	11
Total	$ 1,696	$ 252	$ 24	$ 1,468	$ 628	$ 840

(1) See Note 2(b).

CERC performs its goodwill impairment tests at least annually and evaluates goodwill when events or changes in circumstances indicate that its carrying value may not be recoverable. The impairment evaluation for goodwill is performed by using a two-step process. In the first step, the fair value of each reporting unit is compared with the carrying amount of the reporting unit, including goodwill. The estimated fair value of the reporting unit is generally determined on the basis of discounted cash flows. If the estimated fair value of the reporting unit is less than the carrying amount of the reporting unit, then a second step must be completed in order to determine the amount of the goodwill impairment that should be recorded. In the second step, the implied fair value of the reporting unit's goodwill is determined by allocating the reporting unit's fair value to all of its assets and liabilities other than goodwill (including any unrecognized intangible assets) in a manner similar to a purchase price allocation. The resulting implied fair value of the goodwill that results from the application of this second step is then compared to the carrying amount of the goodwill and an impairment charge is recorded for the difference.

CERC performed its annual impairment test in the third quarter of 2013 and determined, based on the results of the first step, that no impairment charge was required for any reportable segment. Other intangibles were not material as of December 31, 2013 and 2012.

CERC performed its annual impairment test in the third quarter of 2012 and determined that a non-cash goodwill impairment charge in the amount of $252 million was required for the Energy Services reportable segment.

CERC estimated the value of the Energy Services reporting unit using an income approach. Under this approach, the fair value of the reporting unit is determined by using the present value of future expected cash flows, which are based on management projections of revenue growth, gross margin, and overall market conditions. These estimated future cash flows are then discounted using a rate that approximates the weighted average cost of capital of a market participant.

The Energy Services reporting unit fair value analysis resulted in an implied fair value of goodwill of $83 million for this reporting unit, and as a result, a non-cash impairment charge in the amount of $252 million was recorded in the third quarter of 2012. The adverse wholesale market conditions facing CERC's energy services business, specifically the prospects for continued low geographic and seasonal price differentials for natural gas, led to a reduction in the estimate of the fair value of goodwill associated with this reporting unit.

(5) Regulatory Matters

The following is a list of regulatory assets/liabilities reflected on CERC's Consolidated Balance Sheets as of December 31, 2013 and 2012:

	December 31,	
	2013	2012
	(in millions)	
Regulatory assets in other long-term assets (1)	$ 100	$ 105
Regulatory liabilities	(642)	(619)
Net	$ (542)	$ (514)

(1) Regulatory assets that are not earning a return were not material at December 31, 2013 or 2012.

(6) Employee Benefit Plans

(a) Pension Plans

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

CenterPoint Energy's funding policy is to review amounts annually in accordance with applicable regulations in order to achieve adequate funding of projected benefit obligations. Pension expense is allocated to CERC based on covered employees. This calculation is intended to allocate pension costs in the same manner as a separate employer plan. Assets of the plan are not segregated or restricted by CenterPoint Energy's participating subsidiaries. CERC recognized pension expense of $29 million, $32 million and $30 million for the years ended December 31, 2013, 2012 and 2011, respectively.

In addition to the plan, CERC participates in CenterPoint Energy's non-qualified benefit restoration plans, which allow participants to receive the benefits to which they would have been entitled under CenterPoint Energy's non-contributory pension plan except for federally mandated limits on qualified plan benefits or on the level of compensation on which qualified plan benefits may be calculated. The expense associated with the non-qualified pension plan was $2 million for each of the years ended December 31, 2013, 2012 and 2011, respectively.

(b) Savings Plan

CERC participates in CenterPoint Energy's qualified savings plan, which includes a cash or deferred arrangement under Section 401(k) of the Internal Revenue Code of 1986, as amended. Under the plan, participating employees may contribute a portion of their compensation, on a pre-tax or after-tax basis, generally up to a maximum of 50% of eligible compensation. CERC matches 100% of the first 6% of each employee's compensation contributed. The matching contributions are fully vested at all times. CenterPoint Energy allocates to CERC the savings plan benefit expense related to CERC's employees. Savings plan benefit expense was $19 million, $18 million and $17 million for the years ended December 31, 2013, 2012 and 2011, respectively.

(c) Postretirement Benefits

CERC's employees participate in CenterPoint Energy's plans, which provide certain healthcare and life insurance benefits for retired employees on both a contributory and non-contributory basis. Employees become eligible for these benefits if they have met certain age and service requirements at retirement, as defined in the plans. Under plan amendments effective in early 1999, healthcare benefits for future retirees were changed to limit employer contributions for medical coverage. Such benefit costs are accrued over the active service period of employees. CERC is required to fund a portion of its obligations in accordance with rate orders. All other obligations are funded on a pay-as-you-go basis.

The net postretirement benefit cost includes the following components:

	Year Ended December 31,		
	2013	2012	2011
	(in millions)		
Service cost — benefits earned during the period	$ 1	$ 1	$ 1
Interest cost on accumulated benefit obligation	5	5	6
Expected return on plan assets	(1)	(1)	(1)
Amortization of prior service cost	1	2	2
Amortization of net loss	2	3	1
Net postretirement benefit cost	$ 8	$ 10	$ 9

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

	Year Ended December 31,		
	2013	2012	2011
Discount rate	3.90%	4.80%	5.20%
Expected return on plan assets	3.10%	3.10%	4.50%

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

Following are reconciliations of CERC's beginning and ending balances of its postretirement benefit plan's benefit obligation, plan assets and funded status for 2013 and 2012. The measurement dates for plan assets and obligations were December 31, 2013 and 2012.

	December 31,	
	2013	2012
	(in millions, except for actuarial assumptions)	
Change in Benefit Obligation		
Accumulated benefit obligation, beginning of year	$ 133	$ 118
Service cost	1	1
Interest cost	5	5
Benefits paid	(13)	(13)
Participant contributions	4	4
Medicare reimbursement	2	2
Actuarial (gain) loss	(16)	16
Accumulated benefit obligation, end of year	$ 116	$ 133
Change in Plan Assets		
Plan assets, beginning of year	$ 24	$ 22
Benefits paid	(13)	(13)
Employer contributions	9	9
Participant contributions	4	4
Actual investment return	2	2
Plan assets, end of year	$ 26	$ 24
Amounts Recognized in Balance Sheets		
Current liabilities-other	$ (7)	$ (7)
Other liabilities-benefit obligations	(83)	(102)
Net liability, end of year	$ (90)	$ (109)
Actuarial Assumptions		
Discount rate	4.75%	3.90%
Expected long-term return on assets	3.10%	3.10%
Healthcare cost trend rate assumed for the next year - Pre 65	7.00%	9.00%
Healthcare cost trend rate assumed for the next year - Post 65	7.50%	9.00%
Prescription cost trend rate assumed for the next year	7.00%	9.00%
Rate to which the cost trend rate is assumed to decline (ultimate trend rate)	5.50%	5.50%
Year that the healthcare rate reaches the ultimate trend rate	2018	2017
Year that the prescription drug rate reaches the ultimate trend rate	2018	2017

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

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

For measurement purposes, medical costs are assumed to increase to 7.00% and 7.50% for the pre-65 and post-65 retirees, respectively, and the prescription cost is assumed to increase 7.00% during 2014, after which this rate decreases until reaching the ultimate trend rate of 5.50% in 2018.

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

	Year Ended December 31, 2013
Beginning Balance	$ (1)
Other comprehensive income before reclassifications (1)	10
Amounts reclassified from accumulated other comprehensive income:	
Prior service cost (2)	1
Actuarial gains (2)	1
Total reclassifications from accumulated other comprehensive income	2
Tax expense	(6)
Net current period other comprehensive income	6
Ending Balance	$ 5

(1) Total other comprehensive income related to the re-measurement of pension, postretirement and other postemployment plans.

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

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

	December 31,	
	2013	2012
	(in millions)	
Unrecognized actuarial loss	$ 9	$ 20
Unrecognized prior service cost	1	2
Total recognized in accumulated other comprehensive loss	10	22
Less: deferred tax benefit (1)	(15)	(21)
Net amount recognized in accumulated other comprehensive (income) loss	$ (5)	$ 1

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

The changes in plan assets and benefit obligations recognized in other comprehensive income during 2013 are as follows:

	Postretirement Benefits
	(in millions)
Net gain	$ 11
Amortization of prior service cost	1
Total recognized in other comprehensive income	$ 12

The total expense recognized in net periodic costs and other comprehensive income was $4 million for postretirement benefits for the year ended December 31, 2013.

The amounts in accumulated other comprehensive loss expected to be recognized as components of net periodic benefit cost during 2014 are as follows:

	Postretirement Benefits
	(in millions)
Unrecognized actuarial loss	$ —
Unrecognized prior service cost	—
Amounts in accumulated other comprehensive loss to be recognized as net periodic cost	$ —

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

	1% Increase	1% Decrease
	(in millions)	
Effect on the postretirement benefit obligation	$ 2	$ 2
Effect on the total of service and interest cost	—	—

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

As part of the investment strategy discussed above, CERC adopted and maintained the following asset allocation ranges for its postretirement benefit plan:

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

The fair values of CERC's postretirement plan assets at December 31, 2013 and 2012, by asset category are as follows:

	Fair Value Measurements at December 31, 2013 (in millions)			
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Mutual funds (1)	$ 26	$ 26	$ —	$ —
Total	$ 26	$ 26	$ —	$ —

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

	Fair Value Measurements at December 31, 2012 (in millions)			
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Mutual funds (1)	$ 24	$ 24	$ —	$ —
Total	$ 24	$ 24	$ —	$ —

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

CERC expects to contribute $7 million to its postretirement benefits plan in 2014. The following benefit payments are expected to be made by the postretirement benefit plan:

	Postretirement Benefit Plan	
	Benefit Payments	Medicare Subsidy Receipts
	(in millions)	
2014	$ 10	$ (2)
2015	10	(2)
2016	11	(2)
2017	11	(2)
2018	12	(3)
2019-2023	63	(17)

(d) Postemployment Benefits

CERC participates in CenterPoint Energy's plan that provides postemployment benefits for former or inactive employees, their beneficiaries and covered dependents, after employment but before retirement (primarily healthcare and life insurance benefits for participants in the long-term disability plan). CERC recorded postemployment benefit expense of $1 million, $5 million and $4 million for the years ended December 31, 2013, 2012 and 2011, respectively. Amounts relating to postemployment benefits included in "Benefit Obligations" in the accompanying Consolidated Balance Sheets at December 31, 2013 and 2012, were $13 million and $14 million, respectively.

(e) Other Non-Qualified Plans

CERC participates in CenterPoint Energy's deferred compensation plans that provide benefits payable to directors, officers and certain key employees or their designated beneficiaries at specified future dates, upon termination, retirement or death. Benefit payments are made from the general assets of CERC. During 2013, 2012 and 2011, the benefit expense relating to these plans was less than $1 million each year. Amounts relating to deferred compensation plans included in "Benefit Obligations" in the accompanying Consolidated Balance Sheets at December 31, 2013 and 2012 were $3 million and $2 million, respectively.

(f) Other Employee Matters

As of December 31, 2013, approximately 28% of CERC's employees were covered by collective bargaining agreements.

(7) Related Party Transactions

CERC participates in a "money pool" through which it can borrow or invest on a short-term basis. Funding needs are aggregated and external borrowing or investing is based on the net cash position. The net funding requirements of the money pool are expected to be met with borrowings under CenterPoint Energy's revolving credit facility or the sale of CenterPoint Energy's commercial paper. CERC had money pool borrowings of $38 million and $779 million at December 31, 2013 and 2012, respectively, which are included in accounts and notes payable —affiliated companies in the Consolidated Balance Sheets. At December 31, 2013, CERC's money pool borrowings had a weighted-average interest rate of 0.03%.

CERC had net interest expense related to affiliate borrowings of $2 million, $4 million and less than $1 million for the years ended December 31, 2013, 2012 and 2011, respectively.

CenterPoint Energy provides some corporate services to CERC. The costs of services have been charged directly to CERC using methods that management believes are reasonable. These methods include negotiated usage rates, dedicated asset assignment and proportionate corporate formulas based on operating expenses, assets, gross margin, employees and a composite of assets, gross margin and employees. These charges are not necessarily indicative of what would have been incurred had CERC not been an affiliate of CenterPoint Energy. Amounts charged to CERC for these services were $117 million, $163 million and $164 million for 2013, 2012 and 2011, respectively, and are included primarily in operation and maintenance expenses.

No dividends were paid to the parent in 2013, 2012 and 2011.

(8) Derivative Instruments

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

(a) Non-Trading Activities

Derivative Instruments. CERC enters into certain derivative instruments to manage physical commodity price risks and does not engage in proprietary or speculative commodity trading. These financial instruments do not qualify or are not designated as cash flow or fair value hedges.

Weather Hedges. CERC has weather normalization or other rate mechanisms that mitigate the impact of weather on its gas operations in Arkansas, Louisiana, Mississippi and Oklahoma. Gas operations in Texas and Minnesota do not have such mechanisms. As a result, fluctuations from normal weather may have a significant positive or negative effect on Gas Operations' results in Texas and Minnesota.

In 2013 and 2012, CenterPoint Energy entered into heating-degree day swaps for certain Gas Operations jurisdictions to mitigate the effect of fluctuations from normal weather on its results of operations and cash flows for the winter heating season. The swaps are based on ten-year normal weather. During the years ended December 31, 2013, 2012 and 2011, CERC recognized losses of $16 million, gains of $8 million and losses of less than $1 million, respectively, related to these swaps. Weather hedge gains and losses are included in revenues in the Statements of Consolidated Income.

(b) Derivative Fair Values and Income Statement Impacts

The following tables present information about CERC's derivative instruments and hedging activities. The first two tables provide a balance sheet overview of CERC's Derivative Assets and Liabilities as of December 31, 2013 and 2012, while the last table provides a breakdown of the related income statement impacts for the years ending December 31, 2013, 2012 and 2011.

Fair Value of Derivative Instruments

Total derivatives not designated as hedging instruments	Balance Sheet Location	Derivative Assets Fair Value (December 31, 2013)	Derivative Liabilities Fair Value (December 31, 2013)
		(in millions)	
Natural gas derivatives (1) (2) (3)	Current Assets: Non-trading derivative assets	$ 28	$ 4
Natural gas derivatives (1) (3)	Other Assets: Non-trading derivative assets	10	—
Natural gas derivatives (1) (3)	Current Liabilities: Non-trading derivative liabilities	4	21
Natural gas derivatives (1) (3)	Other Liabilities: Non-trading derivative liabilities	1	5
Total		$ 43	$ 30

(1) The fair value shown for natural gas contracts is comprised of derivative gross volumes totaling 607 Bcf or a net 46 Bcf long position. Of the net long position, basis swaps constitute 99 Bcf.

(2) The $28 million Derivative Current Asset includes $1 million related to physical forwards purchased from Enable.

(3) Natural gas contracts are presented on a net basis in the Consolidated Balance Sheets. Natural gas contracts are subject to master netting arrangements. This netting applies to all undisputed amounts due or past due and causes derivative assets (liabilities) to be ultimately presented net in a liability (asset) account within the Consolidated Balance Sheets. The net of total non-trading derivative assets and liabilities was a $13 million asset as shown on CERC's Consolidated Balance Sheets (and as detailed in the table below), and was comprised of the natural gas contracts derivative assets and liabilities separately shown above offset by collateral netting of less than $1 million.

Offsetting of Natural Gas Derivative Assets and Liabilities

	December 31, 2013		
	Gross Amounts Recognized (1)	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amount Presented in the Consolidated Balance Sheets (2)
	(in millions)		
Current Assets: Non-trading derivative assets	$ 32	$ (8)	$ 24
Other Assets: Non-trading derivative assets	11	(1)	10
Current Liabilities: Non-trading derivative liabilities	(25)	8	(17)
Other Liabilities: Non-trading derivative liabilities	(5)	1	(4)
Total	$ 13	$ —	$ 13

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

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

Fair Value of Derivative Instruments

	December 31, 2012		
Total derivatives not designated as hedging instruments	Balance Sheet Location	Derivative Assets Fair Value	Derivative Liabilities Fair Value
		(in millions)	
Natural gas derivatives (1) (2)	Current Assets: Non-trading derivative assets	$ 37	$ 1
Natural gas derivatives (1) (2)	Other Assets: Non-trading derivative assets	6	—
Natural gas derivatives (1) (2)	Current Liabilities: Non-trading derivative liabilities	5	27
Natural gas derivatives (1) (2)	Other Liabilities: Non-trading derivative liabilities	1	4
Total		$ 49	$ 32

(1) The fair value shown for natural gas contracts is comprised of derivative gross volumes totaling 489 billion cubic feet (Bcf) or a net 101 Bcf long position. Of the net long position, basis swaps constitute 73 Bcf.

(2) Natural gas contracts are presented on a net basis in the Consolidated Balance Sheets. Natural gas contracts are subject to master netting arrangements. This netting applies to all undisputed amounts due or past due and causes derivative assets (liabilities) to be ultimately presented net in a liability (asset) account within the Consolidated Balance Sheets. The net of total non-trading derivative assets and liabilities was a $26 million asset as shown on CERC's Consolidated Balance Sheets (and as detailed in the table below), and was comprised of the natural gas contracts derivative assets and liabilities separately shown above offset by collateral netting of $9 million.

Offsetting of Natural Gas Derivative Assets and Liabilities

	December 31, 2012		
	Gross Amounts Recognized (1)	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amount Presented in the Consolidated Balance Sheets (2)
	(in millions)		
Current Assets: Non-trading derivative assets	$ 42	$ (6)	$ 36
Other Assets: Non-trading derivative assets	7	(1)	6
Current Liabilities: Non-trading derivative liabilities	(28)	14	(14)
Other Liabilities: Non-trading derivative liabilities	(4)	2	(2)
Total	$ 17	$ 9	$ 26

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

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

For CERC's price stabilization activities of the Natural Gas Distribution business segment, the settled costs of derivatives are ultimately recovered through purchased gas adjustments. Accordingly, the net unrealized gains and losses associated with these contracts are recorded as net regulatory assets. Realized and unrealized gains and losses on other derivatives are recognized in the Statements of Consolidated Income as revenue for retail sales derivative contracts and as natural gas expense for financial natural gas derivatives and non-retail related physical natural gas derivatives.

Income Statement Impact of Derivative Activity

Total derivatives not designated as hedging instruments	Income Statement Location	Year Ended December 31, 2013	2012	2011
		(in millions)		
Natural gas derivatives	Gains (Losses) in Revenue	$ 11	$ 43	$ 102
Natural gas derivatives (1) (2)	Gains (Losses) in Expense: Natural Gas	10	(63)	(144)
Total		$ 21	$ (20)	$ (42)

(1) The Gains (Losses) in Expense: Natural Gas includes $(2) million during the year ended December 31, 2013 related to physical forwards purchased from Enable.

(2) The Gains (Losses) in Expense: Natural Gas includes $-0-, $(38) million and $(107) million of costs in 2013, 2012 and 2011, respectively, associated with price stabilization activities of the Natural Gas Distribution business segment that will be ultimately recovered through purchased gas adjustments.

(c) Credit Risk Contingent Features

CERC enters into financial derivative contracts containing material adverse change provisions. These provisions could require CERC to post additional collateral if the Standard & Poor's Ratings Services or Moody's Investors Service, Inc. credit ratings of CERC are downgraded. The total fair value of the derivative instruments that contain credit risk contingent features that are in a net liability position at December 31, 2013 and 2012 was $1 million and $5 million, respectively. The aggregate fair value of assets that are already posted as collateral was less than $1 million at both December 31, 2013 and 2012. If all derivative contracts (in a net liability position) containing credit risk contingent features were triggered at December 31, 2013 and 2012, $1 million and $5 million, respectively, of additional assets would be required to be posted as collateral.

(d) Credit Quality of Counterparties

In addition to the risk associated with price movements, credit risk is also inherent in CERC's non-trading derivative activities. Credit risk relates to the risk of loss resulting from non-performance of contractual obligations by a counterparty. The following table shows the composition of counterparties to the non-trading derivative assets of CERC as of December 31, 2013 and 2012 (in millions):

	December 31, 2013		December 31, 2012	
	Investment Grade(1)	Total	Investment Grade(1)	Total
Energy marketers	$ 1	$ 4	$ 1	$ 1
Financial institutions	1	9	—	—
Retail end users (2)	1	21	—	41
Total	$ 3	$ 34	$ 1	$ 42

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

(2) Retail end users represent customers who have contracted to fix the price of a portion of their physical gas requirements for future periods.

(9) Fair Value Measurements

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

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

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

Level 3: Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability. Unobservable inputs reflect CERC's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. CERC develops these inputs based on the best information available, including CERC's own data. A market approach is utilized to value CERC's Level 3 assets or liabilities. Currently, CERC's Level 3 assets and liabilities are comprised of physical forward contracts and options. Level 3 physical forward contracts are valued using a discounted cash flow model which includes illiquid forward price curve locations (ranging from $3.79-$4.94 per one million British thermal units (Btu)) as an unobservable input. Level 3 options are valued through Black-Scholes (including forward start) option models which include option volatilities (ranging from 0-53%) as an unobservable input. CERC's Level 3 derivative assets and liabilities consist of both long and short positions (forwards and options) and their fair value is sensitive to forward prices and volatilities. If forward prices decrease, CERC's long forwards lose value whereas its short forwards gain in value. If volatility decreases, CERC's long options lose value whereas its short options gain in value.

CERC determines the appropriate level for each financial asset and liability on a quarterly basis and recognizes transfers between levels at the end of the reporting period. For the year ended December 31, 2013, there were no transfers between Level 1 and 2 with regard to Natural Gas derivatives. CERC also recognizes purchases of Level 3 financial assets and liabilities at their fair market value at the end of the reporting period.

The following tables present information about CERC's assets and liabilities (including derivatives that are presented net) measured at fair value on a recurring basis as of December 31, 2013 and 2012, and indicate the fair value hierarchy of the valuation techniques utilized by CERC to determine such fair value.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Adjustments (1)	Balance as of December 31, 2013
			(in millions)		
Assets					
Corporate equities	$ 2	$ —	$ —	$ —	$ 2
Investments, including money market funds	11	—	—	—	11
Natural gas derivatives (2)	5	33	5	(9)	34
Total assets	$ 18	$ 33	$ 5	$ (9)	$ 47
Liabilities					
Natural gas derivatives	$ 1	$ 27	$ 2	$ (9)	$ 21
Total liabilities	$ 1	$ 27	$ 2	$ (9)	$ 21

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

(2) The (Level 2) Natural gas derivative assets of $33 million include $1 million related to physical forwards purchased from Enable.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting Adjustments (1)	Balance as of December 31, 2012
			(in millions)		
Assets					
Corporate equities	$ 1	$ —	$ —	$ —	$ 1
Investments, including money market funds	11	—	—	—	11
Natural gas derivatives	1	40	7	(6)	42
Total assets	$ 13	$ 40	$ 7	$ (6)	$ 54
Liabilities					
Natural gas derivatives	$ 5	$ 21	$ 5	$ (15)	$ 16
Total liabilities	$ 5	$ 21	$ 5	$ (15)	$ 16

(1) Amounts represent the impact of legally enforceable master netting agreements that allow CERC to settle positive and negative positions and also include cash collateral of $9 million posted with the same counterparties.

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

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Derivative assets and liabilities, net		
	Year Ended December 31,		
	2013	2012	2011
Beginning balance	$ 2	$ 6	$ 3
Total gains (1)	3	3	6
Total settlements (1)	(3)	(6)	(3)
Total purchases	—	—	2
Transfers out of Level 3	—	(1)	(2)
Transfers into Level 3	1	—	—
Ending balance (2)	$ 3	$ 2	$ 6
The amount of total gains for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at the reporting date	$ 2	$ 1	$ 5

(1) During 2013, 2012 and 2011, CERC did not have Level 3 unrealized gains (losses) or settlements related to price stabilization activities of the Natural Gas Distribution business segment.

(2) During 2013, 2012 and 2011, CERC did not have significant Level 3 sales.

Estimated Fair Value of Financial Instruments

The fair values of cash and cash equivalents and short-term borrowings are estimated to be approximately equivalent to carrying amounts and have been excluded from the table below. Non-trading derivative assets and liabilities are stated at fair value and are excluded from the table below. The fair value of each debt instrument is determined using market interest rates on the applicable dates. These assets and liabilities, which are not measured at fair value in the Consolidated Balance Sheets but for which the fair value is disclosed, would be classified as Level 1 in the fair value hierarchy.

	December 31, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Financial assets:				
Notes receivable - affiliated companies	$ 363	$ 363	$ —	$ —
Financial liabilities:				
Long-term debt	$ 2,240	$ 2,466	$ 2,641	$ 3,094

(10) Unconsolidated Affiliates

As discussed in Note 2, on May 1, 2013 (the Closing Date) CERC Corp., OGE and ArcLight closed on the formation of Enable. Enable owns CenterPoint Midstream, which consists of substantially all of CERC Corp.'s former Interstate Pipelines and Field Services business segments. As a result, CERC no longer has Interstate Pipelines or Field Services business segments. Equity earnings associated with CERC's interest in Enable and equity earnings associated with its retained 25.05% interest in SESH are now reported under the Midstream Investments segment. For a further description of CERC's reportable business segments, see Note 15.

The formation of Enable by CERC has been considered a contribution of in-substance real estate to a limited partnership as the businesses are composed of, and reliant upon, substantial real estate assets and integral equipment. Real estate assets and integral equipment primarily includes gas transmission pipelines, compressor station equipment, rights of way, storage and processing assets and long-term customer contracts. Accordingly, CERC did not recognize a gain or loss upon contribution and recorded its investment in Enable using the equity method of accounting based on the historical cost of the contributed assets and liabilities as of the Closing Date. Approximately $5.8 billion of assets (which includes $4.7 billion in property, plant and equipment, net, $629 million in goodwill and $197 million for the 24.95% investment in SESH) and $1.5 billion of liabilities (which includes the three-year unsecured term loan facility (Term Loan) and the indebtedness owed to CERC, both discussed below, of $1.05 billion and $363 million, respectively) were contributed by CERC Corp. CERC has the ability to significantly influence the operating and financial policies of Enable and, accordingly, recorded an equity method investment, at the historical costs of net assets contributed, of $4.3 billion in Enable on the Closing Date. Pursuant to the MFA, CERC retained certain assets and liabilities historically held by CenterPoint Midstream such as balances relating to federal income taxes and benefit plan obligations.

CERC's investment in Enable is considered to be a VIE because the power to direct the activities that most significantly impact Enable's economic performance does not reside with the holders of equity investment at risk. However, CERC is not considered the primary beneficiary of Enable since it does not have the power to direct the activities of Enable that are considered most significant to the economic performance of Enable. Under the equity method, CERC's investment will be adjusted each period for contributions made, distributions received, CERC's share of Enable's comprehensive income and accretion of any basis difference. CERC's maximum exposure to loss related to Enable is limited to its equity investment as presented in the Consolidated Balance Sheet at December 31, 2013 and its guarantee of Enable's $1.05 billion Term Loan as discussed in Note 13. CERC evaluates its equity method investments for impairment when events or changes in circumstances indicate there is a loss in value of the investment that is other than a temporary decline.

Effective on the Closing Date, CenterPoint Energy and Enable entered into a Services Agreement, Employee Transition Agreement, Transitional Services Agreement and other agreements (collectively, Transition Agreements) whereby CERC agreed to provide certain support services to Enable such as accounting, legal, risk management and treasury functions for an initial term ending on April 30, 2016. The support services automatically extend year-to-year at the end of the initial term, unless terminated by Enable with at least 90 days' notice. Enable may terminate these support services at any time with 180 days' notice if approved by the board of Enable's general partner. Additionally, CERC agreed to provide seconded employees to Enable to support its operations for an initial term ending on December 31, 2014, unless revised by mutual agreement with CenterPoint Energy, OGE and Enable prior to that date. CERC did not transfer any employees to Enable at formation of the partnership or at any time during the year ended December 31, 2013. CERC billed Enable for reimbursement of transitional services, including the costs of seconded employees, of $119 million during the year ended December 31, 2013 under the Transition Agreements. Actual transitional services costs are recorded net of reimbursements received from Enable. CERC had accounts receivable from Enable of $24 million at December 31, 2013 for amounts billed for transitional services, including the cost of seconded employees.

Enable, at its discretion, has the right to select and offer employment to seconded employees from CERC. As of December 31, 2013, CERC determined it cannot reasonably estimate the impact of the costs associated with the termination of employees related to the formation of Enable or transfer of employees from CERC to Enable, including the impact of the changes to the actuarial determination of employee benefit plan obligations. Pursuant to the Transition Agreements, Enable has agreed to reimburse CERC for severance and termination costs related to the termination of CERC's seconded employees, including any potential benefit-related costs, regardless of whether such seconded employees are offered employment by Enable.

On the Closing Date, Enable entered into a $1.05 billion three-year senior unsecured term loan facility (the Term Loan) with third parties and repaid $1.05 billion of affiliated notes payable (Affiliated Notes Payable) owed to CERC. CERC provided a guarantee of Enable's obligations under the Term Loan. The guarantee is subordinated to all senior debt of CERC. Certain of the entities contributed to Enable by CERC are obligated on approximately $363 million of indebtedness owed to CERC bearing interest at an annual rate of 2.10% to 2.45% and scheduled to mature in 2017. CERC recognized interest income of $5 million for the period May 1, 2013 to December 31, 2013 on its notes receivable of $363 million due from 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 partnership 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. CERC can exercise its first put right in May 2014 pursuant to which CERC would contribute an additional 24.95% interest in SESH to Enable.

For the period May 1, 2013 to December 31, 2013, CERC incurred natural gas expenses, including transportation and storage costs, of $123 million for transactions with Enable. CERC had accounts payable to Enable of $22 million at December 31, 2013 from such transactions.

As of December 31, 2013, CERC held an approximate 58.3% limited partner interest in Enable and a 25.05% interest in SESH.

Investment in Unconsolidated Affiliates:

	December 31,	
	2013	2012
Enable	$ 4,319	$ —
SESH (1)	199	404
Other	—	1
Total	$ 4,518	$ 405

(1) On May 1, 2013, CERC contributed a 24.95% interest in SESH to Enable, leaving CERC with a 25.05% interest in SESH.

Equity in Earnings of Unconsolidated Affiliates, net:

	Year Ended December 31,		
	2013	2012	2011
		(in millions)	
Enable	$ 173	$ —	$ —
SESH [1]	15	26	21
Waskom [2]	—	5	9
Total	$ 188	$ 31	$ 30

(1) On May 1, 2013, CERC contributed a 24.95% interest in SESH to Enable, leaving CERC with a 25.05% interest in SESH.

(2) On July 31, 2012, Waskom became a wholly owned subsidiary of CenterPoint Energy. Beginning on August 1, 2012, Waskom's operating results are consolidated on the Statements of Consolidated Income. On May 1, 2013, CenterPoint Energy contributed Waskom to Enable.

Summarized income information for Enable from formation on May 1, 2013 through December 31, 2013 is as follows (in millions):

Operating revenues	$	2,123
Cost of sales, excluding depreciation and amortization		1,241
Operating income		322
Net income attributable to Enable		289
CERC's approximate 58.3% interest	$	168
Basis difference accretion gain		5
CERC's approximate 58.3% interest, net	$	173

Summarized balance sheet information for Enable as of December 31, 2013 is as follows (in millions):

Current assets	$	549
Non-current assets		10,683
Current liabilities		720
Non-current liabilities		2,331
Noncontrolling interest		33
Enable Partners' Capital		8,148
CERC's approximate 58.3% interest	$	4,753
CERC's basis difference		(434)
CERC's investment in Enable	$	4,319

Summarized basis difference information for Enable is as follows (in millions):

Basis difference attributable to goodwill as of May 1, 2013 (1)	$	229
Basis difference to be accreted over 30 years as of May 1, 2013		210
Total basis difference as of May 1, 2013		439
Accumulated accretion of basis difference as of December 31, 2013		(5)
CERC's basis difference in Enable as of December 31, 2013	$	434

(1) This difference related to CERC's proportionate share of Enable's goodwill arising from its acquisition of Enogex, and therefore will not be recognized by CERC.

Enable concluded that the formation of Enable is considered a business combination, and CenterPoint Midstream is the acquirer for accounting purposes. Under this method, the fair value of the consideration paid by CenterPoint Midstream for Enogex is allocated to the assets acquired and liabilities assumed on the Closing Date based on their fair value. Enogex's assets, liabilities and equity were accordingly adjusted to estimated fair value as of May 1, 2013. Determining the fair value of assets and liabilities is judgmental in nature and often involves the use of significant estimates and assumptions. Enable used appraisers to assist in the determination of the estimated fair value of certain assets and liabilities contributed by Enogex.

Cash distributions received from Enable and SESH were approximately $106 million and $23 million, respectively, during the year ended December 31, 2013.

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

	December 31, 2013		December 31, 2012	
	Long-Term	Current(1)	Long-Term	Current(1)
		(in millions)		
Short-term borrowings:				
Inventory financing	$ —	$ 43	$ —	$ 38
Total short-term borrowings	—	43	—	38
Long-term debt:				
Senior notes 4.50% to 6.625% due 2016 to 2041	2,168	—	2,328	365
Commercial paper (2)	118	—	—	—
Unamortized discount and premium	(46)	—	(52)	—
Total long-term debt	2,240	—	2,276	365
Total debt	$ 2,240	$ 43	$ 2,276	$ 403

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

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

(a) Short-term Borrowings

Inventory Financing. Gas Operations has asset management agreements associated with its utility distribution service in Arkansas, north Louisiana and Oklahoma that extend through 2015. Pursuant to the provisions of the agreements, Gas Operations sells natural gas and agrees to repurchase an equivalent amount of natural gas during the winter heating seasons at the same cost, plus a financing charge. These transactions are accounted for as a financing and they had an associated principal obligation of $43 million and $38 million as of December 31, 2013 and 2012, respectively.

(b) Long-term Debt

Debt Repayments. In April 2013, CERC Corp. retired approximately $365 million aggregate principal amount of its 7.875% senior notes at their maturity. The retirement of senior notes was financed by CERC Corp. with the issuance of commercial paper. In May 2013, CERC Corp. applied proceeds from Enable's May 1, 2013 debt repayment of $1.05 billion to the repayment of $357 million aggregate principal amount of its commercial paper and to the May 31, 2013 redemption of $160 million aggregate principal amount of its 5.95% senior notes due January 15, 2014 at 103.419% of their aggregate principal amount.

Revolving Credit Facility. As of December 31, 2013 and 2012, CERC had the following revolving credit facility and utilization of such facility (in millions):

December 31, 2013				December 31, 2012			
Size of Facility	Loans	Letters of Credit	Commercial Paper	Size of Facility	Loans	Letters of Credit	Commercial Paper
$ 600	$ —	$ —	$ 118	$ 950	$ —	$ —	$ —

CERC Corp.'s $600 million credit facility, which is scheduled to terminate September 9, 2018, can be drawn at the London Interbank Offered Rate plus 150 basis points based on CERC Corp.'s current credit ratings. The revolving credit facility contains a financial covenant which limits CERC's consolidated debt to an amount not to exceed 65% of its consolidated capitalization. CERC Corp. was in compliance with all debt covenants as of December 31, 2013.

Maturities. CERC's consolidated maturities of long-term debt are $-0- in 2014, $-0- in 2015, $325 million in 2016, $250 million in 2017 and $418 million in 2018.

(12) Income Taxes

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

	Year Ended December 31,		
	2013	2012	2011
		(in millions)	
Current income tax expense:			
Federal	$ 5	$ —	$ 34
State	9	1	9
Total current expense	14	1	43
Deferred income tax expense:			
Federal	350	198	140
State	7	47	4
Total deferred expense	357	245	144
Total income tax expense	$ 371	$ 246	$ 187

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

	Year Ended December 31,		
	2013	2012	2011
		(in millions)	
Income before income taxes	$ 435	$ 383	$ 503
Federal statutory income tax rate	35%	35%	35%
Expected federal income tax expense	152	134	176
Increase (decrease) in tax expense resulting from:			
State income tax expense, net of federal income tax	23	31	9
Increase (decrease) in settled and uncertain income tax positions	(2)	(7)	1
Tax effect related to the formation of Enable Midstream Partnership	198	—	—
Goodwill impairment	—	88	—
Other, net	—	—	1
Total	219	112	11
Total income tax expense	$ 371	$ 246	$ 187
Effective tax rate	85.3%	64.2%	37.2%

CERC recorded an effective tax rate of 85.3% for 2013 compared to 64.2% for 2012. The increase in the effective tax rate is primarily due to the formation of Enable with deferred tax expense of $225 million related to the book-to-tax basis difference for contributed non-tax deductible goodwill and a tax benefit of $27 million associated with the remeasurement of state deferred taxes at formation. In addition, we recognized a tax benefit of $2 million based on the settlement with the Internal Revenue Service (IRS) of outstanding tax claims for the 2002 and 2003 audit cycles in 2013.

CERC recorded an effective tax rate of 64.2% for 2012 compared to 37.2% for 2011. The increase in the effective tax rate is primarily due to the goodwill impairment of $252 million which is non-deductible for tax in 2012 and higher state tax expense compared to 2011 related to benefits recognized in that prior period for lower blended state rates. The increased rate was partially offset by the release of income tax reserves of $7 million.

CERC recorded a net reduction in state income tax expense of approximately $20 million related to lower blended state tax rates and a reduction of the deferred tax liability recorded in December 2011.

In September 2013, the U.S. Treasury issued final regulations addressing the tax consequences associated with the acquisition, production and improvement of tangible property. CERC does not expect the adoption of the regulations to have a material impact on its financial position, results of operations or cash flows.

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

	December 31,	
	2013	2012
	(in millions)	
Deferred tax assets:		
Current:		
Allowance for doubtful accounts	$ 10	$ 9
Deferred gas costs	7	—
Other	7	—
Total current deferred tax assets	24	9
Non-current:		
Employee benefits	41	49
Loss and credit carryforwards	193	192
Regulatory liabilities, net	—	196
Other	59	51
Total non-current deferred tax assets before valuation allowance	293	488
Valuation allowance	(2)	(2)
Total non-current deferred tax assets, net of valuation allowance	291	486
Total deferred tax assets, net of valuation allowance	315	495
Deferred tax liabilities:		
Current:		
Deferred gas costs	—	25
Other	3	5
Total current deferred tax liabilities	3	30
Non-current:		
Depreciation	746	2,033
Regulatory assets, net	17	—
Investment in unconsolidated affiliates	1,590	—
Other	20	129
Total non-current deferred tax liabilities	2,373	2,162
Total deferred tax liabilities	2,376	2,192
Accumulated deferred income taxes, net	$ 2,061	$ 1,697

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

Tax Attribute Carryforwards and Valuation Allowance. At December 31, 2013, CERC has approximately $495 million of federal net operating loss carryforwards which begin to expire in 2031 and approximately $387 million of state net operating loss carryforwards which expire in various years between 2015 and 2032.

CERC has approximately $244 million of state capital loss carryforwards which expire in 2017 for which management established a full valuation allowance of $3 million state tax effect ($2 million net of federal income tax). The valuation allowance was established based upon management's evaluation that loss carryforwards may not be fully realized.

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

	December 31,		
	2013	2012	2011
		(in millions)	
Balance, beginning of year	$ (20)	$ 8	$ 11
Tax Positions related to prior years:			
Additions	(2)	—	(1)
Reductions	—	(27)	(3)
Tax Positions related to current year:			
Additions	—	—	1
Settlements	22	(1)	—
Balance, end of year	$ —	$ (20)	$ 8

The net decrease in the total amount of unrecognized tax benefits during 2013 is primarily related to CERC's IRS settlements related to open claims for tax years 2002 and 2003. During 2013, the IRS completed the examination cycle and settlement for tax years 2010 and 2011. CERC does not expect the change to the amount of unrecognized tax benefits over the twelve months ending December 31, 2014 to have a material impact on financial position, results of operations and cash flows.

The net decrease in the total amount of unrecognized tax benefits during 2012 is primarily related to the re-measurement of certain unrecognized tax benefits related to an Internal Revenue Service (IRS) issuance of new guidance with respect to repairs on tangible property and CERC's IRS settlements for tax years 2006 through 2009.

CERC had approximately $-0-, $-0- and $6 million of unrecognized tax benefits that, if recognized, would affect the effective income tax rate for 2013, 2012 and 2011, respectively. CERC recognizes interest and penalties as a component of income tax expense. CERC recognized approximately $4 million of income tax benefit, $3 million of income tax expense and $0.4 million of income tax expense related to interest on uncertain income tax positions during 2013, 2012 and 2011, respectively. CERC had approximately $11 million and $7 million of interest receivable on uncertain, including settled, income tax positions accrued at December 31, 2013 and 2012, respectively.

Tax Audits and Settlements. CenterPoint Energy's consolidated federal income tax returns have been audited and settled through tax year 2011. CenterPoint Energy is currently in the early stages of examination by the IRS for tax year 2012. CERC has considered the effects of these examinations in its accrual for settled issues and liability for uncertain income tax positions as of December 31, 2013.

(13) Commitments and Contingencies

(a) Natural Gas Supply Commitments

Natural gas supply commitments include natural gas contracts related to CERC's Natural Gas Distribution and Energy Services business segments, which have various quantity requirements and durations, that are not classified as non-trading derivative assets and liabilities in CERC's Consolidated Balance Sheets as of December 31, 2013 and 2012 as these contracts meet the exception to be classified as "normal purchases contracts" or do not meet the definition of a derivative. Natural gas supply commitments also include natural gas transportation contracts that do not meet the definition of a derivative. As of December 31, 2013, minimum payment obligations for natural gas supply commitments are approximately $408 million in 2014, $391 million in 2015, $310 million in 2016, $250 million in 2017, $244 million in 2018 and $120 million after 2018.

(b) Asset Management Agreements

Gas Operations has asset management agreements (AMAs) associated with its utility distribution service in Arkansas, Louisiana, Mississippi, Oklahoma and Texas. Generally, these AMAs 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 AMAs, 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 AMAs based in part on the results of the asset optimization. Gas Operations has an obligation to purchase its winter storage requirements that have been released to the asset manager under these AMAs. The AMAs have varying terms, the longest of which expires in 2016.

(c) Lease Commitments

The following table sets forth information concerning CERC's obligations under non-cancelable long-term operating leases at December 31, 2013, which primarily consist of rental agreements for building space, data processing equipment, compression equipment and rights of way (in millions):

2014	$	6
2015		4
2016		3
2017		2
2018		2
2019 and beyond		3
Total	$	20

Total lease expense for all operating leases was $20 million, $26 million and $42 million in 2013, 2012 and 2011, respectively.

(d) Legal, Environmental and Other Regulatory Matters

Legal Matters

Gas Market Manipulation Cases. CenterPoint Energy, CenterPoint Houston or their predecessor, Reliant Energy, Incorporated (Reliant Energy), and certain of their former subsidiaries have been named as defendants in certain lawsuits described below. Under a master separation agreement between CenterPoint Energy and a former subsidiary, Reliant Resources, Inc. (RRI), CenterPoint Energy and its subsidiaries are entitled to be indemnified by RRI and its successors for any losses, including certain attorneys' fees and other costs, arising out of these lawsuits. In May 2009, RRI sold its Texas retail business to a subsidiary of NRG Energy, Inc. (NRG) and RRI changed its name to RRI Energy, Inc. In December 2010, Mirant Corporation merged with and became a wholly owned subsidiary of RRI, and RRI changed its name to GenOn Energy, Inc. (GenOn). In December 2012, NRG acquired GenOn through a merger in which GenOn became a wholly owned subsidiary of NRG. None of the sale of the retail business, the merger with Mirant Corporation, or the acquisition of GenOn by NRG alters RRI's (now GenOn's) contractual obligations to indemnify CenterPoint Energy and its subsidiaries, including CenterPoint Houston, for certain liabilities, including their indemnification obligations regarding the gas market manipulation litigation, nor does it affect the terms of existing guarantee arrangements for certain GenOn gas transportation contracts discussed below.

A large number of lawsuits were filed against numerous gas market participants in a number of federal and western state courts in connection with the operation of the natural gas markets in 2000-2002. CenterPoint Energy's former affiliate, RRI, was a participant in gas trading in the California and Western markets. These lawsuits, many of which were filed as class actions, allege violations of state and federal antitrust laws. Plaintiffs in these lawsuits are seeking a variety of forms of relief, including, among others, recovery of compensatory damages (in some cases in excess of $1 billion), a trebling of compensatory damages, full consideration damages and attorneys' fees. CenterPoint Energy and/or Reliant Energy were named in approximately 30 of these lawsuits, which were instituted between 2003 and 2009. CenterPoint Energy and its affiliates have since been released or dismissed from all but one such case. CenterPoint Energy Services, Inc. (CES), a subsidiary of CERC Corp., is a defendant in a case now pending in federal court in Nevada alleging a conspiracy to inflate Wisconsin natural gas prices in 2000-2002. In July 2011, the court issued an order dismissing the plaintiffs' claims against other defendants in the case, each of whom had demonstrated FERC jurisdictional sales for resale during the relevant period, based on federal preemption. The plaintiffs appealed this ruling to the United States Court of Appeals for the

Ninth Circuit, which reversed the trial court's dismissal of the plaintiffs' claims. In August 2013, the other defendants filed a petition for review with the U.S. Supreme Court. CenterPoint Energy believes that CES is not a proper defendant in this case and will continue to pursue a dismissal. CenterPoint Energy does not expect the ultimate outcome of this matter to have a material impact on its financial condition, results of operations or cash flows.

Environmental Matters

Manufactured Gas Plant Sites. CERC and its predecessors operated manufactured gas plants (MGPs) in the past. 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 United States Environmental Protection Agency and other regulators have investigated MGP sites that were owned or operated by CERC or may have been owned by one of its former affiliates. CERC and CenterPoint Energy 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 CenterPoint Energy or CERC.

Asbestos. Some facilities owned by CERC's predecessors contain or have contained asbestos insulation and other asbestos-containing materials. CERC or its predecessor companies have been named, along with numerous others, as a defendant in lawsuits filed by a number of individuals who claim injury due to exposure to asbestos. Some of the claimants have worked at locations owned by CERC, but most existing claims relate to facilities previously owned by CERC's subsidiaries. CERC anticipates that additional claims like those received may be asserted in the future. In 2004 and early 2005, CERC sold its 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 CERC and its 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 CERC has agreed to continue to defend such claims to the extent they are covered by insurance maintained by CERC, subject to reimbursement of the costs of such defense by the NRG affiliate. Although their ultimate outcome cannot be predicted at this time, CERC intends to continue vigorously contesting claims that it does not consider to have merit and, based on its experience to date, does not expect these matters, either individually or in the aggregate, to have a material adverse effect on its financial condition, results of operations or cash flows.

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

Other Proceedings

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

(e) Guarantees

Prior to the distribution of CenterPoint Energy's ownership in RRI to its shareholders, CERC had guaranteed certain contractual obligations of what became RRI's trading subsidiary. When the companies separated, RRI agreed to secure CERC against obligations under the guarantees RRI had been unable to extinguish by the time of separation. Pursuant to such agreement, as amended in December 2007, RRI (now GenOn) agreed to provide to CERC cash or letters of credit as security against CERC's obligations under its remaining guarantees for demand charges under certain gas transportation agreements if and to the extent changes in market conditions expose CERC to a risk of loss on those guarantees based on an annual calculation, with any required collateral to be posted each December. The undiscounted maximum potential payout of the demand charges under these transportation contracts, which will be in effect until 2018, was approximately $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.

CERC Corp. has also provided a guarantee of collection of Enable's obligations under its $1.05 billion Term Loan, which guarantee is subordinated to all senior debt of CERC Corp.

As of December 31, 2013, no amounts have been recorded related to the guarantees discussed above in the Consolidated Balance Sheets.

(14) Unaudited Quarterly Information

Summarized quarterly financial data is as follows:

	Year Ended December 31, 2013			
	First Quarter	Second Quarter (1)	Third Quarter	Fourth Quarter
	(in millions)			
Revenues	$ 1,853	$ 1,235	$ 891	$ 1,543
Operating income	250	56	4	91
Net income (loss)	128	(162)	32	66

	Year Ended December 31, 2012			
	First Quarter	Second Quarter	Third Quarter (2)	Fourth Quarter
	(in millions)			
Revenues	$ 1,550	$ 846	$ 954	$ 1,551
Operating income (loss)	229	106	(152)	211
Net income (loss)	118	42	(127)	104

(1) Effective May 1, 2013, CERC Corp. contributed CenterPoint Midstream to Enable. See Note 2(b) and Note 10 for further discussion on the formation of Enable and CERC's investment in Enable, respectively.

(2) See Note 2(b) and Note (4) for further discussion on the acquisition of additional interest in Waskom and the goodwill impairment charge, respectively.

(15) Reportable Business Segments

Because CERC is an indirect wholly owned subsidiary of CenterPoint Energy, CERC's determination of reportable business segments considers the strategic operating units under which CenterPoint Energy manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments. The accounting policies of the business segments are the same as those described in the summary of significant accounting policies except that some executive benefit costs have not been allocated to business segments. CERC uses operating income as the measure of profit or loss for its business segments.

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

Prior to May 1, 2013, CERC also reported an Interstate Pipelines business segment, which included CenterPoint Energy's interstate natural gas pipeline operations, and a Field Services business segment, which included CERC's non-rate regulated natural gas gathering, processing and treating operations. As previously disclosed, the formation of Enable closed on May 1, 2013. Enable now owns substantially all of CERC's former Interstate Pipelines and Field Services business segments, except for the retained interest in SESH. As a result, effective May 1, 2013, CERC reports equity earnings associated with its interest in Enable and equity earnings associated with its retained interest in SESH under a new Midstream Investments segment, and no longer has Interstate Pipelines and Field Services reporting segments prospectively. See Note 10 for further discussion on Enable formation.

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

Financial data for business segments and products and services are as follows (in millions):

	Revenues from External Customers	Inter-segment Revenues	Depreciation and Amortization	Operating Income (Loss)	Total Assets	Expenditures for Long-Lived Assets
As of and for the year ended December 31, 2013:						
Natural Gas Distribution	$ 2,837	$ 26	$ 185	$ 263	$ 4,976	$ 430
Energy Services	2,374	27	5	13	895	3
Interstate Pipelines (1) (3)	133	53	20	72	—	29
Field Services (2) (3)	178	18	20	73	—	16
Midstream Investments (4)	—	—	—	—	4,518	—
Other	—	—	—	(20)	1,149	—
Reconciling Eliminations	—	(124)	—	—	(996)	—
Consolidated	$ 5,522	$ —	$ 230	$ 401	$ 10,542	$ 478
As of and for the year ended December 31, 2012:						
Natural Gas Distribution	$ 2,320	$ 22	$ 173	$ 226	$ 4,775	$ 359
Energy Services	1,758	26	6	(250)	839	6
Interstate Pipelines (1)	356	146	56	207	4,004	132
Field Services (2)	467	39	50	214	2,453	52
Other	—	—	—	(3)	647	—
Reconciling Eliminations	—	(233)	—	—	(1,528)	—
Consolidated	$ 4,901	$ —	$ 285	$ 394	$ 11,190	$ 549
As of and for the year ended December 31, 2011:						
Natural Gas Distribution	$ 2,823	$ 18	$ 166	$ 226	$ 4,636	$ 295
Energy Services	2,488	23	5	6	1,089	5
Interstate Pipelines (1)	421	132	54	248	3,867	98
Field Services (2)	370	42	37	189	1,894	201
Other	—	—	—	(7)	660	—
Reconciling Eliminations	—	(215)	—	—	(1,459)	—
Consolidated	$ 6,102	$ —	$ 262	$ 662	$ 10,687	$ 599

(1) Interstate Pipelines recorded equity income of $7 million, $26 million and $21 million in the years ended December 31, 2013, 2012 and 2011, respectively, from its 50% interest in SESH, a jointly-owned pipeline. These amounts are included in Equity in earnings of unconsolidated affiliates under the Other Income (Expense) caption. Interstate Pipelines' investment in SESH was $404 million and $409 million as of December 31, 2012 and 2011, respectively, and is included in Investment

in unconsolidated affiliates. As discussed above, effective May 1, 2013, CenterPoint Energy reports equity earnings associated with its interest in Enable and equity earnings associated with its retained interest in SESH under a new Midstream Investments segment, and no longer has an Interstate Pipelines reporting segment prospectively.

(2) Field Services recorded equity income of $5 million and $9 million for the years ended December 31, 2012 and 2011, respectively, from its 50% interest in a jointly-owned gas processing plant. These amounts are included in Equity in earnings of unconsolidated affiliates under the Other Income (Expense) caption. Field Services' investment in the jointly-owned gas processing plant was $63 million as of December 31, 2011, respectively, and is included in Investment in unconsolidated affiliates. Beginning on August 1, 2012, financial results for Waskom are included in operating income due to the July 31, 2012 purchase of the 50% interest in Waskom that CenterPoint Energy did not already own. CERC contributed 100% interest in Waskom to Enable on May 1, 2013. Effective May 1, 2013, CERC equity earnings associated with its interest in Enable under a new Midstream Investments segment, and no longer has a Field Services reporting segment prospectively.

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

(4) Midstream Investments reported equity earnings of $173 million from Enable and $8 million of equity earnings from CERC's retained interest in SESH for the eight months ended December 31, 2013. Included in total assets of Midstream Investments as of December 31, 2013 is $4,319 million related to CERC's investment in Enable and $199 million related to CERC's retained interest in SESH.

Revenues by Products and Services:	Year Ended December 31, 2013	2012	2011
	(in millions)		
Retail gas sales	$ 4,150	$ 3,328	$ 4,019
Wholesale gas sales	913	613	1,149
Gas transportation and processing	345	847	824
Energy products and services	114	113	110
Total	$ 5,522	$ 4,901	$ 6,102

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

None.

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

Disclosure Controls and Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2013 to provide assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding disclosure.

There has been no change in our internal controls over financial reporting that occurred during the three months ended December 31, 2013 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

See report set forth above in Item 8, "Financial Statements and Supplementary Data."

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

The ratio of earnings to fixed charges as calculated pursuant to Securities and Exchange Commission rules was 3.34, 3.05, 3.50, 3.05 and 2.63 for the years ended December 31, 2013, 2012, 2011, 2010 and 2009, respectively.

PART III

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

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

Item 11. ***Executive Compensation***

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

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

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

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

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

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

Aggregate fees billed to CERC during the fiscal years ending December 31, 2013 and 2012 by its principal accounting firm, Deloitte & Touche LLP, are set forth below.

	Year Ended December 31,	
	2013	2012
Audit fees (1)	$ 1,898,216	$ 1,388,798
Audit-related fees (2)	58,000	72,500
Total audit and audit-related fees	1,956,216	1,461,298
Tax fees	—	—
All other fees	—	—
Total fees	$ 1,956,216	$ 1,461,298

(1) For 2013 and 2012, amounts include fees for services provided by the principal accounting firm relating to the integrated audit of financial statements and internal control over financial reporting, statutory audits, attest services, and regulatory filings.

(2) For 2013 and 2012, includes fees for consultations concerning financial accounting and reporting standards and various agreed-upon or expanded procedures related to accounting records to comply with financial accounting or regulatory reporting matters.

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

PART IV

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

(a)(1) Financial Statements.

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

(a)(2) Financial Statement Schedules for the Three Years Ended December 31, 2013

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

I, III, IV and V.

(a)(3) Exhibits.

See Index of Exhibits beginning on page 92.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the consolidated financial statements of CenterPoint Energy Resources Corp. and subsidiaries (the "Company", an indirect wholly owned subsidiary of CenterPoint Energy, Inc.) as of December 31, 2013 and 2012, and for each of the three years in the period ended December 31, 2013, and have issued our report thereon dated March 12, 2014; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company listed in the index at Item 15(a)(2). This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 12, 2014

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES

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

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
For the Three Years Ended December 31, 2013

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions From Reserves (1)	Balance at End of Period
			(in millions)		
Year Ended December 31, 2013:					
Accumulated provisions:					
Uncollectible accounts receivable	$ 23	$ 20	$ —	$ 18	$ 25
Deferred tax asset valuation allowance	2	—	—	—	2
Year Ended December 31, 2012:					
Accumulated provisions:					
Uncollectible accounts receivable	$ 24	$ 15	$ —	$ 16	$ 23
Deferred tax asset valuation allowance	3	(1)	—	—	2
Year Ended December 31, 2011:					
Accumulated provisions:					
Uncollectible accounts receivable	$ 25	$ 25	$ —	$ 26	$ 24
Deferred tax asset valuation allowance	3	—	—	—	3

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, the State of Texas, on the 12th day of March, 2014.

CENTERPOINT ENERGY RESOURCES CORP.
(Registrant)

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 12, 2014.

Signature	Title
/s/ SCOTT M. PROCHAZKA (Scott M. Prochazka)	Chairman, President and Chief Executive Officer (Principal Executive Officer and Director)
/s/ GARY L. WHITLOCK (Gary L. Whitlock)	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ WALTER L. FITZGERALD (Walter L. Fitzgerald)	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES

EXHIBITS TO THE ANNUAL REPORT ON FORM 10-K
For Fiscal Year Ended December 31, 2013

INDEX OF EXHIBITS

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

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

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
4(a)(5)	Supplemental Indenture No. 4, dated as of February 15, 2001, providing for the issuance of RERC Corp.'s 7.75% Notes due 2011	Form 8-K dated February 21, 2001	1-13265	4.1
4(a)(6)	Supplemental Indenture No. 5, dated as of March 25, 2003, providing for the issuance of CERC Corp.'s 7.875% Senior Notes due 2013	Form 8-K dated March 18, 2003	1-13265	4.1
4(a)(7)	Supplemental Indenture No. 6, dated as of April 14, 2003, providing for the issuance of CERC Corp.'s 7.875% Senior Notes due 2013	Form 8-K dated April 7, 2003	1-13265	4.2
4(a)(8)	Supplemental Indenture No. 7, dated as of November 3, 2003, providing for the issuance of CERC Corp.'s 5.95% Senior Notes due 2014	Form 8-K dated October 29, 2003	1-13265	4.2
4(a)(9)	Supplemental Indenture No. 8, dated as of December 28, 2005, providing for the issuance of CERC Corp.'s 6 1/2% Debentures due 2008	CenterPoint Energy, Inc.'s ("CNP's") Form 10-K for the year ended December 31, 2005	1-31447	4(f)(9)
4(a)(10)	Supplemental Indenture No. 9, dated as of May 18, 2006, providing for the issuance of CERC Corp.'s 6.15% Senior Notes due 2016	CNP's Form 10-Q for the quarter ended June 30, 2006	1-31447	4.7
4(a)(11)	Supplemental Indenture No. 10, dated as of February 6, 2007, providing for the issuance of CERC Corp.'s 6.25% Senior Notes due 2037	CNP's Form 10-K for the year ended December 31, 2007	1-31447	4(f)(11)
4(a)(12)	Supplemental Indenture No. 11 dated as of October 23, 2007, providing for the issuance of CERC Corp.'s 6.125% Senior Notes due 2017	CNP's Form 10-Q for quarter ended September 30, 2007	1-31447	4.8
4(a)(13)	Supplemental Indenture No. 12 dated as of October 23, 2007, providing for the issuance of CERC Corp.'s 6.625% Senior Notes due 2037	CNP's Form 10-Q for quarter ended September 30, 2007	1-31447	4.9
4(a)(14)	Supplemental Indenture No. 13 dated as of May 15, 2008, providing for the issuance of CERC Corp.'s 6.00% Senior Notes due 2018	CNP's Form 10-Q for quarter ended June 30, 2008	1-31447	4.9
4(a)(15)	Supplemental Indenture No. 14 to Exhibit 4(a)(1) dated as of January 11, 2011, providing for the issuance of CERC Corp.'s 4.50% Senior Notes due 2021 and 5.85% Senior Notes due 2041	CNP's Form 10-K for the year ended December 31, 2010	1-31447	4(a)(15)
4(a)(16)	Supplemental Indenture No. 15 to Exhibit 4(a)(1) dated as of January 20, 2011, providing for the issuance of CERC Corp.'s 4.50% Senior Notes due 2021	CNP's Form 10-K for the year ended December 31, 2010	1-31447	4(a)(16)
4(b)(1)	$950,000,000 Credit Agreement dated as of September 9, 2011, among CERC Corp., as Borrower, and the banks named therein	Form 8-K dated September 9, 2011	1-31447	4.3
4(b)(2)	First Amendment to Credit Agreement, dated April 11, 2013, by and among CERC Corp., Citibank, N.A., as administrative agent, and the banks party thereto.	Form 8-K dated April 11, 2013	1-31447	4.2
4(b)(3)	Second Amendment to Credit Agreement, dated September 9, 2013, by and among CERC Corp., Citibank, N.A., as administrative agent, and the banks party thereto.	Form 8-K dated September 9, 2013	1-31447	4.3

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

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	
10(a)	Service Agreement by and between Mississippi River Transmission Corporation and Laclede Gas Company dated August 22, 1989	NorAm's Form 10-K for the year ended December 31, 1989	1-13265	10.20
10(b)	Commitment Letter dated March 14, 2013 by and among CenterPoint Energy, Inc., Enogex LLC, Citigroup Global Markets Inc., UBS Loan Finance LLC and UBS Securities LLC relating to a $1,050,000,000 3-year unsecured term loan facility.	Form 8-K dated March 14, 2013	1-31447	10.1
10(c)	Commitment Letter dated March 14, 2013 by and among CenterPoint Energy, Inc., Enogex LLC, Citigroup Global Markets Inc., UBS Loan Finance LLC and UBS Securities LLC relating to a $1,400,000,000 5-year unsecured revolving credit facility.	Form 8-K dated March 14, 2013	1-31447	10.2
10(d)	First Amended and Restated Agreement of Limited Partnership of CenterPoint Energy Field Services LP dated as of May 1, 2013.	Form 8-K dated May 1, 2013	1-31447	10.1
10(e)	First Amendment to the First Amended and Restated Agreement of Limited Partnership of CenterPoint Energy Field Services LP dated as of July 30, 2013.	CNP's Form 10-Q for the quarter ended September 30, 2013	1-31447	10.1
10(f)	Amended and Restated Limited Liability Company Agreement of CNP OGE GP LLC dated as of May 1, 2013.	Form 8-K dated May 1, 2013	1-31447	10.2
10(g)	Second Amended and Restated Limited Liability Company Agreement of Enable GP, LLC dated as of July 30, 2013.	CNP's Form 10-Q for the quarter ended September 30, 2013	1-31447	10.2
10(h)	Registration Rights Agreement dated as of May 1, 2013 by and among CenterPoint Energy Field Services LP, CERC Corp., OGE Enogex Holdings LLC, and Enogex Holdings LLC.	Form 8-K dated May 1, 2013	1-31447	10.3
10(i)	Omnibus Agreement dated as of May 1, 2013 among CenterPoint Energy, Inc., OGE Energy Corp., Enogex Holdings LLC and CenterPoint Energy Field Services LP.	Form 8-K dated May 1, 2013	1-31447	10.4
10(j)	Term Loan Facility dated as of May 1, 2013 by and among CenterPoint Energy Field Services LP and Citibank, N.A., as administrative agent, UBS Securities LLC, as syndication agent, JPMorgan Chase Bank, N.A. and Wells Fargo Bank, National Association as co-documentation agents, and the several lenders thereto relating to a $1,050,000,000 3-year unsecured term loan facility.	Form 8-K dated May 1, 2013	1-31447	10.5
10(k)	First Amendment and Waiver to Term Loan Agreement dated as of January 23, 2014 by and among Enable Midstream Partners, LP, the lenders party thereto and Citibank, N.A., as agent.	CNP's Form 10-K for the year ended December 31, 2013	1-31447	99.4

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
10(l)	Revolving Credit Agreement dated as of May 1, 2013 by and among CenterPoint Energy Field Services LP and Citibank, N.A., as administrative agent, UBS Securities LLC, as syndication agent, JPMorgan Chase Bank, N.A. and Wells Fargo Bank, National Association, as co-documentation agents, the several lenders from time to time party thereto and the letter of credit issuers from time to time party thereto relating to a $1,400,000,000 5-year unsecured revolving credit facility.	Form 8-K dated May 1, 2013	1-31447	10.6
10(m)	First Amendment and Waiver to Revolving Credit Agreement dated as of January 23, 2014 by and among Enable Midstream Partners, LP, the lenders party thereto and Citibank, N.A., as agent.	CNP's Form 10-K for the year ended December 31, 2013	1-31447	99.3
10(n)	Subordinated Guaranty of Collection dated as of May 1, 2013 by CERC Corp. in favor of Citibank, N.A., as agent.	Form 8-K dated May 1, 2013	1-31447	10.7
+12	Computation of Ratios of Earnings to Fixed Charges			
+23.1	Consent of Deloitte & Touche LLP			
+23.2	Consent of Deloitte & Touche LLP, Independent Registered Public Accounting Firm of Enable Midstream Partners, LP			
+31.1	Rule 13a-14(a)/15d-14(a) Certification of Scott M. Prochazka			
+31.2	Rule 13a-14(a)/15d-14(a) Certification of Gary L. Whitlock			
+32.1	Section 1350 Certification of Scott M. Prochazka			
+32.2	Section 1350 Certification of Gary L. Whitlock			
+99.1	Financial Statements of Enable Midstream Partners, LP as of December 31, 2013 and 2012 and for the years ended December 31, 2013, 2012 and 2011.			
+101.INS	XBRL Instance Document			
+101.SCH	XBRL Taxonomy Extension Schema Document			
+101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document			
+101.DEF	XBRL Taxonomy Extension Definition Linkbase Document			
+101.LAB	XBRL Taxonomy Extension Labels Linkbase Document			
+101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document			

Exhibit 12

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

COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
(Millions of Dollars)

	Year Ended December 31,				
	2013 (1)	2012 (1)	2011 (1)	2010 (1)	2009 (1)
Net Income	$ 64	$ 137	$ 316	$ 300	$ 230
Equity in earnings of unconsolidated affiliates, net of distributions	(58)	8	8	13	(3)
Income taxes	371	246	187	187	146
Capitalized interest	(1)	(2)	—	(7)	(2)
	376	389	511	493	371
Fixed charges, as defined:					
Interest	154	179	190	208	213
Capitalized interest	1	2	—	7	2
Interest component of rentals charged to operating expense	6	9	14	25	12
Total fixed charges	161	190	204	240	227
Earnings, as defined	$ 537	$ 579	$ 715	$ 733	$ 598
Ratio of earnings to fixed charges	3.34	3.05	3.50	3.05	2.63

(1) Excluded from the computation of fixed charges for the years ended December 31, 2013, 2012, 2011, 2010 and 2009 is interest income of $3 million, $3 million, $-0-, $1 million and $-0-, respectively, which is included in income tax expense.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-193695-01 on Form S-3 of our reports dated March 12, 2014, relating to the consolidated financial statements and financial statement schedule of CenterPoint Energy Resources Corp. and subsidiaries, appearing in this Annual Report on Form 10-K of CenterPoint Energy Resources Corp. for the year ended December 31, 2013.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 12, 2014

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-193695-01 on Form S-3 of CenterPoint Energy Resources Corp. of our report dated February 21, 2014, relating to the combined and consolidated financial statements of Enable Midstream Partners, LP (previously named CenterPoint Energy Field Services, LLC) and subsidiaries, (collectively the "Partnership") (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the preparation of the combined and consolidated financial statements of Enable Midstream Partners, LP from the historical accounting records maintained by CenterPoint Energy, Inc. and its subsidiaries), appearing in this Annual Report on Form 10-K of CenterPoint Energy Resources Corp. for the year ended December 31, 2013.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 12, 2014

Exhibit 31.1

CERTIFICATIONS

I, Scott M. Prochazka, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: March 12, 2014

/s/ Scott M. Prochazka

Scott M. Prochazka
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATIONS

I, Gary L. Whitlock, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: March 12, 2014

/s/ Gary L. Whitlock

Gary L. Whitlock
Executive Vice President and Chief Financial Officer

Exhibit 32.1

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

In connection with the Annual Report of CenterPoint Energy Resources Corp. (the “Company”) on Form 10-K for the year ended December 31, 2013 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, I, Scott M. Prochazka, Chief Executive Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

/s/ Scott M. Prochazka

Scott M. Prochazka
President and Chief Executive Officer
March 12, 2014

Exhibit 32.2

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

In connection with the Annual Report of CenterPoint Energy Resources Corp. (the “Company”) on Form 10-K for the year ended December 31, 2013 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, I, Gary L. Whitlock, Chief Financial Officer, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

/s/ Gary L. Whitlock

Gary L. Whitlock
Executive Vice President and Chief Financial Officer
March 12, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Members of
Enable Midstream Partners, LP
Oklahoma City, Oklahoma

We have audited the accompanying combined and consolidated balance sheets of Enable Midstream Partners, LP (previously named CenterPoint Energy Field Services, LLC) and subsidiaries (the "Partnership") as of December 31, 2013 and 2012, and the related combined and consolidated statements of income, comprehensive income, cash flows, and parent net equity and partners’ capital for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the financial statements based on our audits.

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

In our opinion, such combined and consolidated financial statements present fairly, in all material respects, the financial position of Enable Midstream Partners, LP and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the combined and consolidated financial statements, the combined and consolidated financial statements have been prepared from the historical accounting records maintained by CenterPoint Energy, Inc. and its subsidiaries for the Partnership until May 1, 2013 and may not necessarily be indicative of the financial position, results of operations and cash flows that would have existed had the Partnership operated as a separate and unaffiliated company until the Partnership formation on May 1, 2013. All of the Partnership’s combined entities were under common control and management for the periods presented until May 1, 2013. Beginning on May 1, 2013, the Partnership consolidated Enogex LLC and all previously combined entities.

/s/ Deloitte & Touche LLP

Houston, Texas
February 21, 2014

ENABLE MIDSTREAM PARTNERS, LP

COMBINED AND CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Revenues (including revenues from affiliates (Note 11))	$ 2,489	$ 952	$ 932
Cost of Goods Sold, excluding depreciation and amortization (including expenses from affiliates (Note 11))	1,313	129	101
Operating Expenses:			
Operation and maintenance (including expenses from affiliates (Note 11))	429	267	263
Depreciation and amortization	212	106	91
Impairment	12	—	—
Taxes other than income taxes	54	34	37
Total Operating Expenses	707	407	391
Operating Income	469	416	440
Other Income (Expense):			
Interest expense (including expenses from affiliates (Note 11))	(67)	(85)	(90)
Equity in earnings of equity method affiliates	15	31	31
Interest income—affiliated companies	9	21	14
Step acquisition gain	—	136	—
Total	(43)	103	(45)
Income Before Income Taxes	426	519	395
Income tax expense (benefit)	(1,192)	203	163
Net Income	$ 1,618	$ 316	$ 232
Less: Net income attributable to noncontrolling interest	3	—	—
Net Income attributable to Enable Midstream Partners, LP	$ 1,615	$ 316	$ 232
Limited partners' interest in net income attributable to Enable Midstream Partners, LP (Note 1)	$ 289	$ —	$ —
Number of outstanding limited partner units	499	—	—
Basic and diluted earnings per limited partner unit	$ 0.58	$ —	$ —

See Notes to the Combined and Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

COMBINED AND CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2013	**2012**	**2011**
		(In millions)	
Net Income	$ 1,618	$ 316	$ 232
Other comprehensive income	—	—	—
Comprehensive income	$ 1,618	$ 316	$ 232
Less: Comprehensive income attributable to noncontrolling interest	3	—	—
Comprehensive income attributable to Enable Midstream Partners, LP	$ 1,615	$ 316	$ 232

See Notes to the Combined and Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

COMBINED AND CONSOLIDATED BALANCE SHEETS

ASSETS	**December 31, 2013**	**December 31, 2012**
	(In millions)	
Current Assets:		
Cash and cash equivalents	$ 108	$ —
Accounts receivable	306	78
Accounts receivable—affiliated companies	28	25
Notes receivable—affiliated companies	—	479
Inventory	83	57
Taxes receivable	—	45
Deferred income tax assets	—	31
Gas imbalances	10	—
Other current assets	14	24
Total current assets	549	739
Property, Plant and Equipment:		
Property, plant and equipment	9,655	5,175
Less: accumulated depreciation and amortization	665	470
Property, plant and equipment, net	8,990	4,705
Other Assets:		
Intangible assets, net	383	—
Goodwill	1,068	629
Investment in equity method affiliates	198	405
Other	44	4
Total other assets	1,693	1,038
Total Assets	$ 11,232	$ 6,482

See Notes to the Combined and Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

COMBINED AND CONSOLIDATED BALANCE SHEETS, continued

LIABILITIES AND PARTNERS' CAPITAL	**December 31,**	
	2013	**2012**
Current Liabilities:	**(In millions)**	
Accounts payable	$ 400	$ 83
Accounts payable—affiliated companies	40	28
Current portion of long-term debt	204	—
Notes payable—affiliated companies	—	753
Taxes accrued	20	25
Gas imbalances	13	7
Other	43	26
Total current liabilities	720	922
Other Liabilities:		
Accumulated deferred income taxes, net	8	1,272
Notes payable—affiliated companies	363	1,009
Benefit obligations	—	21
Regulatory liabilities	16	16
Other	28	21
Total other liabilities	415	2,339
Long-Term Debt	1,916	—
Commitments and Contingencies (Note 12)		
Partners' Capital:		
Partners' Capital	8,148	3,221
Accumulated other comprehensive loss	–	(6)
Total Enable Midstream Partners, LP Partners' Capital	8,148	3,215
Noncontrolling interest	33	6
Total Partners' Capital	8,181	3,221
Total Liabilities and Partners' Capital	$ 11,232	$ 6,482

See Notes to the Combined and Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

COMBINED AND CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Cash Flows from Operating Activities:			
Net income	$ 1,618	$ 316	$ 232
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	212	106	91
Deferred income taxes	(1,194)	196	176
Impairments	12	—	—
Step acquisition gain	—	(136)	—
Gain on sale/retirement of assets	2	—	—
Equity in earnings of equity method affiliates, net of distributions	9	8	8
Changes in other assets and liabilities:			
Accounts receivable, net	(81)	(9)	45
Accounts receivable – affiliated companies	(4)	1	28
Inventory	(6)	2	13
Taxes receivable	19	(1)	13
Other current assets	15	(3)	10
Other assets	1	—	3
Accounts payable	62	(3)	7
Accounts payable – affiliated companies	3	(3)	(1)
Taxes accrued	—	(19)	21
Other current liabilities	(2)	(4)	(3)
Other liabilities	(18)	—	19
Net cash provided by operating activities	648	451	662
Cash Flows from Investing Activities:			
Capital expenditures, net of acquisitions	(573)	(202)	(346)
Acquisitions, net of cash	—	(360)	—
Decrease (increase) in notes receivable affiliated companies	434	(77)	(219)
Investment in equity method affiliates	—	(5)	(13)
Other, net	(1)	(1)	18
Net cash used in investing activities	(140)	(645)	(560)
Cash Flows from Financing Activities:			
Proceeds from long-term debt, net of issuance costs	1,046	—	—
Proceeds from line of credit	1,126	—	—
Repayment of line of credit	(754)	—	—
Increase (decrease) notes payable – affiliated companies	(1,542)	194	(102)
Repayment of advance with affiliated companies	(136)	—	—
Capital contributions from partners	43	—	—
Distribution to partners	(183)	—	—
Net cash provided by (used in) financing activities	(400)	194	(102)
Net Change in Cash and Cash Equivalents	108	—	—
Cash and Cash Equivalents at Beginning of the Year	—	—	—
Cash and Cash Equivalents at End of the Year	$ 108	$ —	$ —

See Notes to the Combined and Consolidated Financial Statements

COMBINED AND CONSOLIDATED STATEMENTS OF CASH FLOWS, continued

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest, net of capitalized interest	$ 65	$ 85	$ 90
Income taxes (refunds), net	(9)	26	(67)
Non-cash transactions:			
Accounts payable related to capital expenditures	$ 43	$ 37	$ 31
Acquisition of Enogex (Note 3)	3,788	–	–

See Notes to the Combined and Consolidated Financial Statements

COMBINED AND CONSOLIDATED STATEMENTS OF ENABLE MIDSTREAM PARTNERS, LP PARENT NET EQUITY AND PARTNERS' CAPITAL

	Partners' Capital		Parent Net Investment	Accumulated Other Comprehensive Loss	Total Enable Midstream Partners, LP Partners' Capital	Noncontrolling Interest	Total Partners' Capital
	Units	Value	Value	Value	Value	Value	Value
	(In millions)						
Balance as of December 31, 2010	—	$ —	$ 2,672	$ (6)	$ 2,666	$ 6	$ 2,672
Net income	—	—	232	—	232	—	232
Balance as of December 31, 2011	—	$ —	$ 2,904	$ (6)	$ 2,898	$ 6	$ 2,904
Net income	—	—	316	—	316		316
Net transfers from parent	—	—	1	—	1	—	1
Balance as of December 31, 2012	—	$ —	$ 3,221	$ (6)	$ 3,215	$ 6	$ 3,221
Net income	—	—	1,326	—	1,326	—	1,326
Contributions from (Distributions to) CenterPoint Energy prior to formation (Note 1)	—	—	(295)	6	(289)	—	(289)
Balance as of April 30, 2013	—	$ —	$ 4,252	$ —	$ 4,252	$ 6	$ 4,258
Conversion to a limited partnership	291	4,252	(4,252)	—	—	—	—
Issuance of units upon acquisition of Enogex on May 1, 2013 (Note 3)	208	3,788	—	—	3,788	26	3,814
Net income	—	289	—	—	289	3	292
Distributions to Partners	—	(181)	—	—	(181)	(2)	(183)
Balance as of December 31, 2013	499	$ 8,148	$ —	$ —	$ 8,148	$ 33	$ 8,181

See Notes to the Combined and Consolidated Financial Statements

NOTES TO THE COMBINED AND CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Organization

Enable Midstream Partners, LP (Partnership) is a private limited partnership formed on May 1, 2013 by CenterPoint Energy, Inc. (CenterPoint Energy), OGE Energy Corp. (OGE Energy) and affiliates of ArcLight Capital Partners, LLC (ArcLight), pursuant to the terms of the Master Formation Agreement dated March 14,2013 (MFA). The Partnership is a large-scale, growth-oriented limited partnership formed to own, operate and develop strategically located natural gas and crude oil infrastructure assets. The Partnership's assets and operations are organized into two business segments: (i) Gathering and Processing, which primarily provides natural gas and crude oil gathering, processing and fractionation services for our 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. The natural gas gathering and processing assets are strategically located in four states and serve natural gas production in the Anadarko, Arkoma and Ark-La-Tex basins. This segment also includes an emerging crude oil gathering business in the Bakken shale formation, principally located in the Williston basin. The 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, CenterPoint Energy, OGE Energy and ArcLight hold approximately 58.3%, 28.5% and 13.2%, respectively, of the limited partner interests in the Partnership. The general partner of the Partnership is Enable GP, LLC (General Partner). The limited partner interests of the Partnership have limited voting rights on matters affecting the business. As such, limited partners do not have rights to elect the Partnership's General Partner on an annual or continuing basis and may not remove the Partnership's General Partner without at least 75% vote by all unitholders, including all units held by the Partnership's limited partners, and General Partner and its affiliates, voting together as a single class.

The Partnership is controlled equally by CenterPoint Energy and OGE Energy, who each have 50% of the management rights of the General Partner. The General Partner was established by CenterPoint Energy and OGE Energy to govern the Partnership and has no other operating activities. The General Partner is governed by a board made up of an equal number of representatives designated by each of CenterPoint Energy and OGE Energy, along with board members CenterPoint Energy and OGE Energy mutually agree to appoint. Based on the 50/50 management ownership, with neither company having control, effective May 1, 2013, CenterPoint Energy and OGE Energy deconsolidated their interests in the Partnership and Enogex LLC (Enogex), respectively. Effective July 30, 2013, the name of Enogex was changed to Enable Oklahoma Intrastate Transmission, LLC (Enable Oklahoma).

CenterPoint Energy and OGE Energy also own a 40% and 60% interest, respectively, in the incentive distribution rights held by the General Partner. In addition, for a period of time prior to an initial public offering, ArcLight will have protective approval rights over certain material activities of the Partnership, 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.

Upon conversion to a limited partnership on May 1, 2013, the Partnership's earnings are no longer subject to income tax (other than Texas state margin taxes) and are taxable at the individual partner level. As a result of the conversion to a partnership immediately prior to formation, CenterPoint Energy assumed all outstanding current income tax liabilities and the Partnership derecognized the deferred income tax assets and liabilities by recording an income tax benefit of $1.24 billion. Consequently, the Combined and Consolidated Statements of Income do not include an income tax provision on income earned on or after May 1, 2013 (other than Texas state margin taxes). See Note 13 for further discussion of the Partnership's income taxes.

Prior to May 1, 2013, the financial statements of the Partnership include Enable Gas Transmission, LLC (EGT), Enable Mississippi River Transmission, LLC (MRT), and the non-rate regulated natural gas gathering, processing and treating operations (consisting of CenterPoint Energy Field Services, LLC and its subsidiaries), which were under common control by CenterPoint Energy, and a 50% interest in Southeast Supply Header, LLC (SESH). On May 1, 2013, CenterPoint Energy converted CenterPoint Energy Field Services, LLC, an indirect wholly owned subsidiary into a Delaware limited partnership, which subsequently changed its name to Enable Midstream Partners, LP.

As discussed in Note 1 under "Enable Midstream Partners, LP Parent Net Equity and Partners' Capital," through the Partnership formation on May 1, 2013, CenterPoint Energy retained certain assets and liabilities and related balances in accumulated other comprehensive loss, historically held by the Partnership, such as certain intercompany notes payable to CenterPoint Energy and benefit plan obligations. Additionally, the Partnership distributed a 25.05% interest in SESH to CenterPoint Energy, subject to future acquisition by the Partnership through put and call options discussed in Note 7. On May 1, 2013, OGE Energy and ArcLight indirectly contributed 100% of the equity interests in Enogex to the Partnership in exchange for limited partner interests and, for OGE Energy only, interests in the General Partner. The Partnership concluded that the Partnership formation on May 1, 2013 was considered a business combination, and for accounting purposes, the Partnership was the acquirer of Enogex. Subsequent to May 1, 2013, the financial statements of the Partnership are consolidated to reflect the acquisition of Enogex, and the remaining 24.95% interest in SESH. See Note 3 for further discussion of the acquisition of Enogex.

In addition, as of December 31, 2013, as a result of the acquisition of Enogex on May 1, 2013, the Partnership holds a 50% ownership interest in Atoka Midstream LLC (Atoka). As of December 31, 2013, the Partnership consolidated Atoka in its Combined and Consolidated Financial Statements as Enable Oklahoma acted as the managing member of Atoka and had control over the operations of Atoka.

On November 26, 2013, the Partnership filed a registration statement with the Securities and Exchange Commission for a proposed initial public offering of its common units, representing limited partner interests in the Partnership (the Offering). At the date of these financial statements, the registration statement relating to the Offering is not effective. The completion of the Offering is subject to numerous conditions and no assurances can be made that it will be successfully completed. The securities offered under the registration statement may not be sold, nor may offers to buy be accepted, prior to the time that the registration statement becomes effective. The information contained in these financial statements with respect to the Offering shall not constitute an offer to sell or a solicitation of an offer to buy any securities.

Basis of Presentation

These combined and consolidated financial statements and related notes of the Partnership have been prepared in accordance with accounting principles generally accepted in the United States. For accounting and financial reporting purposes, (i) the formation of the Partnership is considered a contribution of real estate by CenterPoint Energy and is reflected at CenterPoint Energy's historical cost as of May 1, 2013 and (ii) the Partnership acquired Enogex on May 1, 2013.

These combined and consolidated financial statements have been prepared from the historical accounting records maintained by CenterPoint Energy for the Partnership until May 1, 2013 and may not necessarily be indicative of the condition that would have existed or the results of operations if the Partnership had been operated as a separate and unaffiliated entity. All of Partnership's combined entities were under common control and management for the periods presented until May 1, 2013, and all intercompany transactions and balances are eliminated in combination and consolidation, as applicable. Beginning on May 1, 2013, the Partnership consolidated Enogex and all previously combined entities of the Partnership.

These combined and consolidated financial statements and the related financial statement disclosures reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective periods.

For a description of the Partnership's reportable business segments, see Note 14.

Enable Midstream Partners, LP Parent Net Equity and Partners' Capital

Prior to May 1, 2013, Enable Midstream Partners, LP Parent Net Equity on the Combined Balance Sheet represents the investment of CenterPoint Energy in the Partnership. On April 30, 2013 immediately prior to formation of the limited partnership, while under common control, CenterPoint Energy completed equity transactions with the Partnership, whereby CenterPoint Energy made a cash contribution to the Partnership and retained certain assets and liabilities previously held by the Partnership, all of which were deemed to be transfers of net assets not constituting a transfer of a business, as follows:

	Amounts retained prior to May 1, 2013	
	(In millions)	
Contributions from (Distributions to) CenterPoint Energy		
Cash	$	40
Pension and postretirement plans		22
Deferred financing cost		6
Investment in 25.05% of SESH (see Note 7)		(197)
Increase in Notes payable—affiliated companies (see Note 11)		(143)
Decrease in Notes receivable—affiliated companies (see Note 11)		(45)
Income tax obligations, net		28
Net distributions to CenterPoint Energy prior to formation	$	(289)

Effective May 1, 2013, Enable Midstream Partners, LP Partners' Capital on the Consolidated Balance Sheet represents the net amount of capital, accumulated net income, contributions and distributions affecting the investments of CenterPoint Energy, OGE Energy, and ArcLight in the Partnership. On August 14, 2013 and November 14, 2013, the Partnership distributed $61 million and $120 million to the unitholders of record as of July 1, 2013 and October 1, 2013, respectively.

Earnings per Limited Partner Unit

Earnings per limited partner unit is calculated by dividing the limited partners' interest in net income attributable to Enable Midstream Partners, LP by the weighted average number of limited partner units outstanding. Earnings per limited partner unit assumes that cash distributions are equal to the limited partners' interest in net income attributable to Enable Midstream Partners, LP. Limited partners' interest in net income attributable to Enable Midstream Partners, LP reflects net income attributable to Enable Midstream Partners, LP subsequent to its formation as a limited partnership on May 1, 2013, as no limited partner units were outstanding prior to this date. The 8,086,945 and 32,413 limited partner units that may be issued in connection with acquiring the additional 24.95% and 0.10% interests in SESH, respectively, as discussed in Note 7, are not included in the calculation of diluted earnings per limited partner unit as the impact of the potential transactions is anti-dilutive.

Use of Estimates

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

Revenues

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

The Partnership recognizes revenue from natural gas gathering, processing, transportation and storage services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold. The partnership records deferred revenue when it receives consideration from a third party before achieving certain criteria that must be met for revenue to be recognized in accordance with GAAP. The Partnership has $9 million and $-0- of deferred revenues on the Consolidated and Combined Balance Sheets as of December 31, 2013 and 2012, respectively.

The Partnership relies on certain key natural gas producer customers for a significant portion of natural gas and NGLs supply. The Partnership relies on certain key utilities for a significant portion of transportation and storage demand. The Partnership depends on third-party facilities to transport and fractionate NGLs that it delivers to third parties at the inlet of their facilities. Additionally for the year ended December 31,2013, one third party purchases approximately 30% of the NGLs delivered to its system, which accounted for approximately $232 million or 9% of total revenue. Other than revenues from affiliates discussed in Note 11, there are no other revenue concentrations with individual customers in the year ended December 31, 2013, 2012 and 2011.

Natural Gas Purchases

Estimates for gas purchases are based on estimated volumes and contracted purchase prices. Estimated gas purchases are included in Accounts Payable or Accounts Payable—affiliated companies, as appropriate on the Combined or Consolidated Balance Sheets and in Cost of Goods Sold, excluding Depreciation and Amortization on the Combined and Consolidated Statements of Income.

Environmental Costs

The Partnership expenses or capitalizes environmental expenditures, as appropriate, depending on their future economic benefit. The Partnership expenses amounts that relate to an existing condition caused by past operations that do not have future economic benefit. The Partnership records undiscounted liabilities related to these future costs when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated. There are no material amounts accrued at December 31, 2013 or 2012.

Depreciation and Amortization Expense

Depreciation is computed using the straight-line method based on economic lives or a regulatory-mandated recovery period. Amortization of intangible assets is computed using the straight-line method over the respective lives of the intangible assets.

During 2013, the Partnership completed a depreciation study for the Gathering and Processing segment, as well as the acquired Enogex assets. The new depreciation rates have been applied prospectively. There were no material changes in weighted average useful lives for pre-acquisition Gathering and Processing assets.

Income Taxes

Prior to May 1, 2013, the Partnership was included in the consolidated income tax returns of CenterPoint Energy. The Partnership calculated its income tax provision on a separate return basis under a tax sharing agreement with CenterPoint Energy. The Partnership used the asset and liability method of accounting for deferred income taxes in accordance with accounting guidance for income taxes. Deferred income tax assets and liabilities were recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. A valuation allowance was established against deferred tax assets for which management believed realization was not considered more likely than not. Current federal and certain state income taxes were payable to or receivable from CenterPoint Energy. The Partnership recognized interest and penalties as a component of income tax expense. Upon conversion to a limited partnership on May 1, 2013, the Partnership's earnings are no longer subject to income tax (other than Texas state margin taxes) and are taxable at the individual partner level. For more information, see Note 13.

Cash and Cash Equivalents

The Partnership considers cash equivalents to be short-term, highly liquid investments with maturities of three months or less from the date of purchase. The Combined or Consolidated Balance Sheets have $108 million and $-0- of cash and cash equivalents as of December 31, 2013 and 2012, respectively.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount and do not bear interest. It is the policy of management to review the outstanding accounts receivable monthly, as well as the bad debt write-offs experienced in the past. Based on this review, management determined that no allowance for doubtful accounts was required as of December 31, 2013 and 2012.

Inventory

Materials and supplies inventory is valued at cost and is subsequently recorded at the lower of cost or market. During the year ended December 31, 2013, the Partnership recorded write-downs to market value related to materials and supplies inventory of $2 million associated with the Service Star business line impairment discussed in Note 9. No such write-downs were recorded in the years ended December 31, 2012 and 2011. Materials and supplies are recorded to inventory when purchased and, as appropriate, subsequently charged to Operation and maintenance expense on the Combined and Consolidated Statements of Income or capitalized to Property, plant and equipment on the Combined or Consolidated Balance Sheets when installed.

Natural gas inventory is held, through the Transportation and Storage business segment, to provide operational support for the intrastate pipeline deliveries and to manage leased intrastate storage capacity. Natural gas liquids inventory is held, through the Gathering and Processing business segment, due to timing differences between the production of certain natural gas liquids and ultimate sale to third parties. Natural gas and natural gas liquids inventory is valued using moving average cost and is subsequently recorded at the lower of cost or market. During the year ended December 31, 2013, the Partnership recorded write-downs to market value related to natural gas and natural gas liquids inventory of $4 million. No such write-downs were recorded in the years ended December 31, 2012 and 2011. The cost of gas associated with sales of natural gas and natural gas liquids inventory is presented in Cost of goods sold, excluding depreciation and amortization on the Combined and Consolidated Statements of Income.

	December 31,	
	2013	**2012**
	(In millions)	
Materials and supplies	$ 60	$ 56
Natural gas inventory	23	1
Total inventory	$ 83	$ 57

Gas Imbalances

Gas imbalances occur when the actual amounts of natural gas delivered from or received by the Partnership's pipeline system differ from the amounts scheduled to be delivered or received. Imbalances are due to or due from shippers and operators and can be settled in cash or made up in-kind depending on contractual terms. The Partnership values all imbalances at individual, or where appropriate an average of, current market indices applicable to the Partnership's operations, not to exceed net realizable value.

Long-Lived Assets (including Intangible Assets)

The Partnership records property, plant and equipment and intangible assets at historical cost. The Partnership expenses repair and maintenance costs as incurred.

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

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

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

Regulatory Assets and Liabilities

The Partnership applies the guidance for accounting for regulated operations to portions of the Transportation and Storage business segment. The Partnership's rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. As of each of December 31, 2013 and 2012, these removal costs of $16 million are classified as regulatory liabilities in the Combined or Consolidated Balance Sheets.

Capitalization of Interest and Allowance for Funds Used During Construction

Allowance for funds used during construction (AFUDC) represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases both utility plant and earnings, it is realized in cash when the assets are included in rates for combined entities that apply guidance for accounting for regulated operations. Interest and AFUDC are capitalized as a component of projects under construction and will be amortized over the assets' estimated useful lives. During the year ended December 31, 2013, 2012 and 2011, the Partnership capitalized interest and AFUDC of $7 million, $2 million and $-0- million, respectively.

Derivative Instruments

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

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

Fair Value Measurements

The Partnership determines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. As required, the Partnership utilizes valuation techniques that maximize the use of observable inputs (levels 1 and 2) and minimize the use of unobservable inputs (level 3) within the fair value hierarchy included in current accounting guidance. The Partnership generally applies the market approach to determine fair value. This method uses pricing and other information generated by market transactions for identical or comparable assets and liabilities. Assets and liabilities are classified within the fair value hierarchy based on the lowest level (least observable) input that is significant to the measurement in its entirety.

Accumulated Other Comprehensive Loss

There were no material changes in the components of accumulated other comprehensive loss attributable to the Partnership during the year ended December 31, 2013. At both December 31, 2013 and 2012, there was no accumulated other comprehensive loss related to the Partnership's noncontrolling interest.

No significant amounts were reclassified out of accumulated other comprehensive loss to net income during the year ended December 31, 2013, 2012 and 2011.

(2) New Accounting Pronouncements

In February 2013, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2013-02, "Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income" (ASU 2013-02). The objective of ASU 2013-02 is to improve the transparency of changes in other comprehensive income and items reclassified out of Accumulated Other Comprehensive Income in financial statements. This new guidance is effective for a reporting entity's first reporting period beginning after December 15, 2012 and should be applied prospectively. The Partnership's adoption of this new guidance on January 1, 2013 did not have a material impact on its financial position, results of operations or cash flows.

In December 2011 and January 2013, the FASB issued Accounting Standards Update No. 2011-11, "Disclosures About Offsetting Assets and Liabilities" (ASU 2011-11) and No. 2013-01, "Clarifying the Scope of Disclosures About Offsetting Assets and Liabilities" (ASU 2013-01), respectively. The objective of ASU 2011-11 is to enhance disclosures about the nature of an entity's rights of setoff and related arrangements associated with its financial instruments and derivative instruments. The objective of ASU 2013-01 is to clarify which instruments and transactions are subject to ASU 2011-11. Both ASU 2011-11 and ASU 2013-01 are effective for a reporting entity's first reporting period beginning on or after January 1, 2013 and should be applied retrospectively. The Partnership's adoption of this new guidance on January 1, 2013 did not have a material impact on its combined and consolidated financial position, results of operations or cash flows.

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

(3) Acquisition of Enogex

Under the acquisition method, the fair value of the consideration transferred by the Partnership to OGE Energy and ArcLight for the contribution of Enogex in exchange for interest in the Partnership is allocated to the assets acquired and liabilities assumed on May 1, 2013 based on their estimated fair value. Enogex's assets, liabilities and equity are recorded at their estimated fair value as of May 1, 2013, and beginning on May 1, 2013, the Partnership consolidated Enogex. The Partnership completed the purchase price allocation for this transaction in the fourth quarter of 2013.

On May 1, 2013, in accordance with the MFA, CenterPoint Energy, OGE Energy, and ArcLight received 291,002,583 common units, 141,956,176 common units, and 65,908,224 common units, respectively representing limited partner interests in the Partnership. The fair value of consideration transferred to OGE Energy and ArcLight in exchange for the contribution of Enogex consists of the fair value of the limited and general partner interests. The Partnership utilized the market approach to estimate the fair value of the limited partner interests, general partner interests and Atoka, also giving consideration to alternative methods such as the income and cost approaches as it relates to the underlying assets and liabilities. The primary inputs for the market valuation are the historical and current year forecasted cash flows and market multiples. The primary inputs for the income approach are forecasted cash flows and discount rates. The primary inputs for the cost approach are costs for similar assets and ages of the assets. All fair value measurements of assets acquired and liabilities assumed are based on a combination of inputs that are not observable in the market and thus represent Level 3 inputs.

The Partnership incurred no acquisition related costs in the Combined and Consolidated Statement of Income based upon the terms in the MFA related to the acquisition of Enogex.

The following table summarizes the amounts recognized by the Partnership for the estimated fair value of assets acquired and liabilities assumed for the acquisition of 100% interest Enogex as of May 1, 2013 and is reconciled to the consideration transferred by the Partnership (in millions):

		Amounts Recognized as of May 1, 2013
Assets		
Current Assets	$	192
Property, plant and equipment		3,919
Goodwill		439
Other intangible assets		401
Other assets		21
Total assets	$	4,972
Liabilities		
Current Liabilities	$	393
Long-term debt		745
Other liabilities		20
Total liabilities		1,158
Less: Noncontrolling interest at fair value		26
Fair value of consideration transferred	$	3,788

The amounts of Enogex's revenue, operating income, net income and net income attributable to Enable Midstream Partners, LP included in the Partnership's Combined and Consolidated Statement of Income for the period from May 1, 2013 through December 31, 2013 are as follows (in millions):

Revenues	$	1,406
Operating income		92
Net income		77
Net income attributable to Enable Midstream Partners, LP		74

See Note 7 for discussion of the Partnership's acquisition of Waskom during 2012.

Impact on Depreciation

The property, plant and equipment acquired from Enogex have differing weighted average useful lives from the existing assets of the Partnership. These assets will be depreciated over a weighted average estimated useful life of 32 years.

Unaudited Pro forma Results of Operations

The Partnership's unaudited pro forma results of operations in the combined entity had the acquisition of Enogex been completed on January 1, 2012 are as follows (in millions):

	Year ended December 31,	
	2013	2012
Unaudited pro forma results of operations:		
Pro forma revenues	$ 3,120	$ 2,563
Pro forma operating income	487	558
Pro forma net income	1,638	433
Pro forma net income attributable to Enable Midstream Partners, LP	1,635	431

The unaudited pro forma results of operations include adjustments to:

- Include the historical results of Enogex beginning on January 1, 2012;
- Include incremental depreciation and amortization incurred on the step-up of Enogex's assets;
- Include adjustments to revenue and cost of sales to reflect Enogex purchase price adjustments for the recurring impact of certain loss contracts and deferred revenues; and
- Include a reduction to interest expense for recognition of a premium on Enogex's fixed rate senior notes.

The unaudited pro forma information is not necessarily indicative of the results of operations that would have occurred had the transactions been made at the beginning of the periods presented or the future results of the consolidated operations.

(4) Property, Plant and Equipment

Property, plant and equipment includes the following:

	Weighted Average Useful Lives	December 31,	
	(Years)	2013	2012
Property, plant and equipment, gross:		(In millions)	
Gathering and Processing	35	$ 5,123	$ 2,339
Transportation and Storage	42	4,300	2,772
Construction work-in-progress		232	64
Total		$ 9,655	$ 5,175
Accumulated depreciation:			
Gathering and Processing		213	118
Transportation and Storage		452	352
Total accumulated depreciation		665	470
Property, plant and equipment, net		$ 8,990	$ 4,705

(5) Intangible Assets, Net

Prior to May 1, 2013, the Partnership did not have any intangible assets. Associated with the acquisition of Enogex, the Partnership recorded $401 million in intangible assets associated with customer relationships. Intangible assets are as follows as of December 31, 2013 (in millions):

	Acquisition of Enogex	Accumulated Amortization	Net Intangible Assets
Customer relationships	$ 401	$ 18	$ 383
Total	$ 401	$ 18	$ 383

The Partnership determined that intangible assets have a weighted average useful life of 15 years for customer relationships as of May 1, 2013. Intangible assets do not have any significant residual value or renewal options of existing terms. There are no intangible assets with indefinite useful lives.

Amortization expense in the year ended December 31, 2013 is $18 million. The following table summarizes the Partnership's expected amortization of intangible assets for each of the next five years (in millions).

	2014	2015	2016	2017	2018
Expected amortization of intangible assets	$ 27	$ 27	$ 27	$ 27	$ 27

(6) Goodwill

The excess of the consideration transferred over the fair value of the net assets acquired is allocated to goodwill. The goodwill arising from the acquisition of Enogex consists largely of the synergies and economies of scale expected from combining the operations of the Partnership and Enogex. The Partnership determined that its reporting units are one level below the Gathering and Processing and Transportation and Storage business segment level at the operating segment level.

Goodwill by reportable segment is as follows (in millions):

	Gathering and Processing	Transportation and Storage	Total
Balance at January 1	$ 26	$ 579	$ 605
Acquisition of Waskom	24	—	24
Balance at December 31, 2012	$ 50	$ 579	$ 629
Acquisition of Enogex	439	–	439
Balance at December 31, 2013	$ 489	$ 579	$ 1,068

The Partnership does not amortize goodwill but instead annually assesses goodwill for impairment. The Partnership performed an interim test upon formation as a limited partnership on May 1, 2013 and its annual impairment tests in the fourth quarter of 2013 and the third quarters of 2012 and 2011. The Partnership determined that no impairment charge for goodwill was required for the years ended December 31, 2013, 2012 and 2011. See Note 1 for further discussion regarding goodwill impairment testing.

(7) Investments in Equity Method Affiliates

The Partnership uses the equity method of accounting for investments in entities in which it has an ownership interest between 20% and 50% and exercises significant influence. Until May 1, 2013, the Partnership held a 50% investment in SESH, a 270-mile interstate natural gas pipeline, which was accounted for as an investment in equity method affiliates. On May 1, 2013, the Partnership distributed a 25.05% interest in SESH to CenterPoint Energy, retaining a 24.95% interest in SESH.

Following the distribution of SESH, CenterPoint Energy indirectly owns a 25.05% interest in SESH that may be contributed to Partnership in the future, upon exercise of certain put or call rights, under which CenterPoint Energy would contribute to the Partnership CenterPoint Energy's retained interest in SESH at a price equal to the fair market value of such interest at the time the put right or call right is exercised (which may be no earlier than May 2014 and May 2015 for 24.95% and 0.1% interest, respectively). If CenterPoint Energy were to exercise such put right or the Partnership were to exercise such call right, CenterPoint Energy's retained interest in SESH would be contributed to the Partnership in exchange for consideration consisting of 8,086,945 and 32,413 limited partnership units (subject to certain adjustments) for 24.95% and 0.1% interest in SESH, respectively, and, subject to certain restrictions, a cash payment, payable either from CenterPoint Energy to the Partnership or from the Partnership to CenterPoint Energy, in an amount such that the total consideration exchanged is equal in value to the fair market value of the contributed interest in SESH, subject to adjustment for accretion and dilution events. Affiliates of Spectra Energy Corp. own the remaining 50% interest in SESH.

Prior to July 2012, the Partnership owned a 50% interest in Waskom, a natural gas processing plant, which was accounted as an investment in equity method affiliates.

On July 31, 2012, the Partnership purchased the 50% interest that it did not already own in Waskom, as well as other gathering and related assets from a third-party for approximately $273 million in cash. The amount of the purchase price allocated to the acquisition of the 50% interest in Waskom was approximately $201 million, with the remaining purchase price allocated to the other gathering assets. The $273 million purchase price was allocated to the fair value of assets received as follows: $253 million to property, plant and equipment; $16 million to goodwill; and the remaining balance to other assets and liabilities. The original 50% interest held by Partnership in Waskom had a fair value of approximately $201 million prior to its acquisition of the additional 50% interest in Waskom, based on a discounted cash flow methodology (a level 3 valuation technique for which the key inputs are the discount rate and operating cash flow projections). The purchase of the additional 50% interest in Waskom was determined to be a business combination achieved in stages, and as such the Partnership recorded a pre-tax gain of approximately $136 million and goodwill of $8 million on July 31, 2012, which is the result of Partnership remeasuring its original 50% interest in Waskom to fair value. As a result of the purchase, Partnership combined its wholly owned investment in Waskom beginning on July 31, 2012, which included goodwill totaling $24 million, consisting of $17 million related to Waskom (including the re-measurement of its existing 50% interest) and $7 million related to the other gathering and related assets. On May 1, 2013, CenterPoint Energy contributed a 100% interest in Waskom to the Partnership.

Investment in Equity Method Affiliates:

	December 31,	
	2013	2012
	(In millions)	
SESH	$ 198	$ 404
Other	—	1
Total	$ 198	$ 405

Equity in Earnings of Equity Method Affiliates:

	Year Ended December 31,		
	2013 (1)	2012 (2)	2011
		(In millions)	
Waskom	$ —	$ 5	$ 10
SESH	15	26	21
Total	$ 15	$ 31	$ 31

(1) Until May 1, 2013, the combined results of operations for Partnership reflect a 50% interest in SESH, as historically combined in the Partnership's financial statements. On May 1, 2013, the Partnership distributed a 25.05% interest in SESH to CenterPoint Energy, retaining a 24.95% interest in SESH.

(2) On July 31, 2012, Waskom became a wholly owned subsidiary of the Partnership. Beginning on August 1, 2012, Waskom's operating results are combined or consolidated, as appropriate, in the Combined and Consolidated Statement of Income

Summarized financial information of SESH is presented below:

	December 31,	
	2013	2012
Balance Sheets:	(In millions)	
Current assets	$ 53	$ 51
Property, plant and equipment, net	1,132	1,147
Other non-current assets	—	1
Total assets	$ 1,185	$ 1,199
Current liabilities	$ 20	$ 19
Non-current liabilities	375	377
Member's equity	790	803
Total liabilities and member's equity	$ 1,185	$ 1,199
Reconciliation:		
Investment in SESH	$ 198	$ 404
Less: Capitalized interest on investment in SESH	(1)	(2)
The Partnership's share of member's equity	$ 197	$ 402

	Year Ended December 31,		
	2013	2012	2011
Income Statements:	(In millions)		
Revenues	$ 107	$ 110	$ 100
Operating income	66	71	61
Net income	47	52	42

(8) Debt

Prior to May 1, 2013, the Partnership's debt was all payable to affiliates, which is discussed in Note 11 as notes payable—affiliated companies. The Partnership's third party debt effective May 1, 2013 is as follows:

On May 1, 2013, the Partnership entered into a $1.05 billion three-year senior unsecured term loan facility (Term Loan Facility), the proceeds of which were used to repay $1.05 billion of intercompany indebtedness owed to CenterPoint Energy. A wholly owned subsidiary of CenterPoint Energy has guaranteed collection of the Partnership's obligations under the Term Loan Facility, which guarantee is subordinated to all senior debt of such wholly owned subsidiary of CenterPoint Energy.

On May 1, 2013, the Partnership also entered into a $1.4 billion, five-year senior unsecured revolving credit facility (Revolving Credit Facility) in accordance with the terms of the MFA, discussed in Note 1. As of December 31, 2013, there was $333 million in principal advances and $2 million in letters of credit outstanding under the Revolving Credit Facility.

The Term Loan Facility and the Revolving Credit Facility each permit outstanding borrowings to bear interest at the London Interbank Offered Rate (LIBOR) and/or an alternate base rate, at the Partnership's election, plus an applicable margin. The applicable margin is based on the Partnership's applicable credit ratings. As of December 31, 2013, the applicable margin for LIBOR-based borrowings under the Term Loan Facility and the Revolving Credit Facility was 1.625% based on the Partnership's credit ratings. In addition, the Revolving Credit Facility requires the Partnership to pay a fee on unused commitments. The commitment fee is based on the Partnership's applicable credit rating from the rating agencies. As of December 31, 2013, the commitment fee under the Revolving Credit Facility was 0.25% per annum based on the Partnership's credit ratings.

Effective May 1, 2013, the Partnership's debt includes Enable Oklahoma's $200 million of 6.875% senior notes due July of 2014 and $250 million of 6.25% senior notes due March of 2020 (collectively, the Enable Oklahoma Senior Notes).

The Enable Oklahoma Senior Notes have a $37 million unamortized premium at December 31, 2013, of which $4 million relates to the senior notes due July of 2014 and $33 million relates to the senior notes due March of 2020, resulting in an effective interest rate of 3.39% and 3.77%, respectively, during the year ended December 31, 2013. Additionally, the Partnership's debt includes Enable Oklahoma's $250 million variable rate term loan (Enable Oklahoma Term Loan). The Enable Oklahoma Term Loan permits outstanding borrowings to bear interest at the London Interbank Offered Rate (LIBOR) and/or an alternate base rate, at Enable Oklahoma's election, plus an applicable margin. The applicable margin is based on Enable Oklahoma's applicable credit ratings. As of December 31, 2013, the applicable margin for LIBOR-based borrowings under the Enable Oklahoma Term Loan was 1.50% based on Enable Oklahoma's credit ratings.

Maturities of long-term debt, excluding unamortized premiums, are as follows:

		Long-term debt
2014	$	200
2015		250
2016		1,050
2017		—
2018		333
Thereafter		250

Unamortized debt expense of $9 million and $-0- at December 31, 2013 and 2012, respectively, is classified in Other assets in the Combined or Consolidated Balance Sheets and is being amortized over the life of the respective debt using the effective interest method. Unamortized premium on long-term debt of $37 million and $-0- as of December 31, 2013 and 2012, respectively, is classified as either Long-term debt or Current portion of long-term debt, consistent with the underlying debt instrument, in the Combined or Consolidated Balance Sheets and is being amortized over the life of the respective debt using the effective interest method.

As of December 31, 2013, the Partnership and Enable Oklahoma complied with all of their debt agreements, including financial covenants.

(9) Fair Value Measurements

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

Level 1: Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date. Instruments classified as Level 1 include natural gas futures, swaps and options transactions for contracts traded on the New York Mercantile Exchange (NYMEX) and settled through a NYMEX clearing broker.

Level 2: Inputs, other than quoted prices included in Level 1, are observable for the asset or liability, either directly or indirectly. Level 2 inputs include quoted prices for similar instruments in active markets, and inputs other than quoted prices that are observable for the asset or liability. Fair value assets and liabilities that are generally included in this category are derivatives with fair values based on inputs from actively quoted markets. Instruments classified as Level 2 include over-the-counter NYMEX natural gas swaps, natural gas basis swaps and natural gas purchase and sales transactions in markets such that the pricing is closely related to the NYMEX pricing, and over-the-counter West Texas Intermediate (WTI) crude swaps for condensate sales.

Level 3: Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability. Unobservable inputs reflect the Partnership's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Partnership develops these inputs based on the best information available, including the Partnership's own data.

The Partnership utilizes the market approach in determining the fair value of its derivative positions by using either NYMEX or WTI published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX published market prices may be considered Level 1 if they are settled through a NYMEX clearing broker account with daily margining. Over-the-counter derivatives with NYMEX or WTI based prices are considered Level 2 due to the impact of counterparty credit risk. Valuations based on independent broker pricing or broker/dealer valuations may be classified as Level 2 only to the extent they may be validated by an additional source of independent market data for an identical or closely related active market. In certain less liquid markets or for longer-term contracts, forward prices are not as readily available. In these circumstances, contracts are valued using internally developed methodologies that consider historical relationships among various quoted prices in active markets that result in management's best estimate of fair value. These contracts are classified as Level 3.

The Partnership determines the appropriate level for each financial asset and liability on a quarterly basis and recognizes transfers between levels at the end of the reporting period. For the year ended December 31, 2013, there were no transfers between Level 1 and 2 and no Level 3 investments were held.

The impact to the fair value of derivatives due to credit risk is calculated using the probability of default based on Standard & Poor's Ratings Services and/or internally generated ratings. The fair value of derivative assets is adjusted for credit risk. The fair value of derivative liabilities is adjusted for credit risk only if the impact is deemed material.

Estimated Fair Value of Financial Instruments

The fair values of all accounts receivable, notes receivable, accounts payable, short-term notes payable— affiliated companies, and other such financial instruments on the Combined and Consolidated Balance Sheets are estimated to be approximately equivalent to their carrying amounts and have been excluded from the table below. The following table summarizes the fair value and carrying amount of the Partnership's financial instruments at December 31, 2013 and 2012 (in millions). The Company had no material financial instruments measured at fair value on a recurring basis at December 31, 2013 and 2012.

	December 31,			
	2013		2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long Term Debt:	(In millions)			
Long-term notes payable—affiliated companies (Level 2)	$ 363	$ 363	$ 1,009	$ 1,232
Revolving Credit Facility (Level 2)	333	333	—	—
Term Loan Facility (Level 2)	1,050	1,050	—	—
Enable Oklahoma Term Loan (Level 2)	250	250	—	—
Enable Oklahoma Senior Notes (Level 2)(1)	487	477	—	—

(1) Includes $204 million of current portion as of December 31, 2013.

The fair value of the Partnership's Term Loan Facility and Long-term notes payable—affiliated companies, along with the Enable Oklahoma Senior Notes, is based on quoted market prices and estimates of current rates available for similar issues with similar maturities and is classified as Level 2 in the fair value hierarchy.

Non-Financial Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis; that is, the assets and liabilities are not measured at fair value on an ongoing basis, but are subject to fair value adjustments in certain circumstances (e.g., when there is evidence of impairment).

During the year ended December 31, 2013, the Partnership remeasured the Service Star assets at fair value. Upon formation as a private partnership on May 1, 2013, management of the Partnership reassessed the long-term strategy related to the Service Star business line, a component of the Gathering and Processing business segment which provides measurement and communication services to third parties. Based on forecasted future undiscounted cash flows management determined that the carrying value of the Service Star assets were not fully recoverable. The Partnership utilized the income approach (generally accepted valuation approach) to estimate the fair value of these assets. The primary inputs are forecast cash flows and the discount rate. The fair value measurement is based on inputs that are not observable in the market and thus represent level 3 inputs. Applying a discounted cash flow model to the property, plant and equipment and reviewing the associated materials and supplies inventory, during the year ended December 31, 2013 the Partnership recognized a $12 million impairment, consisting of a $10 million write-down of property, plant and equipment and a $2 million write-down of materials and supplies inventory considered either excess or obsolete.

At December 31, 2012, no material fair value adjustments or fair value measurements were required for these non-financial assets or liabilities.

Contracts with Master Netting Arrangements

Fair value amounts recognized for forward, interest rate swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Combined or Consolidated Balance Sheets. The Partnership has presented the fair values of its derivative contracts under master netting agreements using a net fair value presentation. The Partnership had no material commodity contracts recorded at fair value on its Combined or Consolidated Balance Sheet at December 31, 2013 and 2012.

The following tables summarize the Partnership's assets and liabilities that are measured at fair value on a recurring basis at December 31, 2013 (in millions):

	Gas Imbalances(A)	
	Assets(B)	**Liabilities(C)**
Significant other observable inputs (Level 2)	$ 8	$ 10

(A) The Partnership uses the market approach to fair value its gas imbalance assets and liabilities at individual, or where appropriate an average of, current market indices applicable to the Partnership's operations, not to exceed net realizable value. Gas imbalances held by Enable Oklahoma are valued using an average of the Inside FERC Gas Market Report for Panhandle Eastern Pipe Line Co. (Texas, Oklahoma Mainline), ONEOK (Oklahoma) and ANR Pipeline (Oklahoma) indices. There were no netting adjustments as of December 31, 2013.

(B) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of $2 million at December 31, 2013, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

(C) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of $3 million at December 31, 2013, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

The Partnership has no material assets or liability measured at fair value on a recurring basis at December 31, 2012.

(10) Derivative Instruments and Hedging Activities

The Partnership is exposed to certain risks relating to its ongoing business operations. The primary risks managed using derivatives instruments are commodity price risk and interest rate risk. The Partnership is also exposed to credit risk in its business operations.

Commodity Price Risk

The Partnership has used forward physical contracts, commodity price swap contracts and commodity price option features to manage the Partnership's commodity price risk exposures in the past. Commodity derivative instruments used by the Partnership are as follows:

- NGL put options and NGL swaps are used to manage the Partnership's NGL exposure associated with its processing agreements;

- natural gas swaps are used to manage the Partnership's keep-whole natural gas exposure associated with its processing operations and the Partnership's natural gas exposure associated with operating its gathering, transportation and storage assets; and
- natural gas futures and swaps, natural gas options and natural gas commodity purchases and sales are used to manage the Partnership's natural gas exposure associated with its storage and transportation contracts and asset management activities.

Normal purchases and normal sales contracts are not recorded in the Combined or Consolidated Balance Sheets and earnings are recognized in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales treatment to: (i) commodity contracts for the purchase and sale of natural gas used in or produced by the Partnership's operations and (ii) commodity contracts for the purchase and sale of NGLs produced by Partnership's Gathering and Processing segment.

The Partnership recognizes its non-exchange traded derivative instruments in the Combined or Consolidated Balance Sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. Exchange traded transactions are settled on a net basis daily through margin accounts with a clearing broker and, therefore, are recorded at fair value on a net basis in Other current assets in the Combined or Consolidated Balance Sheets.

Credit Risk

The Partnership is exposed to certain credit risks relating to its ongoing business operations. Credit risk includes the risk that counterparties that owe the Partnership money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, the Partnership may be forced to enter into alternative arrangements. In that event, Partnership's financial results could be adversely affected and the Partnership could incur losses.

Cash Flow Hedges

For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of Accumulated other comprehensive income (loss) and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portion of a derivative's change in fair value or hedge components excluded from the assessment of effectiveness is recognized currently in earnings. The Partnership measures the ineffectiveness of commodity cash flow hedges using the change in fair value method whereby the change in the expected future cash flows designated as the hedge transaction are compared to the change in fair value of the hedging instrument. Forecasted transactions, which are designated as the hedged transaction in a cash flow hedge, are regularly evaluated to assess whether they continue to be probable of occurring. If the forecasted transactions are no longer probable of occurring, hedge accounting will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings.

The Partnership designates as cash flow hedges derivatives used to manage commodity price risk exposure for the Partnership's NGLs volumes and corresponding keep-whole natural gas resulting from its natural gas processing contracts (processing hedges) and natural gas positions resulting from its natural gas gathering and processing operations and natural gas transportation and storage operations (operational gas hedges). The Partnership also designates as cash flow hedges certain derivatives used to manage natural gas commodity exposure for certain natural gas storage inventory positions. The Partnership had no instruments designated as cash flow hedges at December 31, 2013 and 2012.

Fair Value Hedges

For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedge risk are recognized currently in earnings. The Partnership includes the gain or loss on the hedged items in Revenues, offsetting the loss or gain on the related hedging derivative.

At December 31, 2013 and 2012, the Partnership had no derivative instruments that were designated as fair value hedges.

Derivatives Not Designated as Hedging Instruments

Derivative instruments not designated as hedging instruments are utilized in the Partnership's asset management activities. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized currently in earnings, unless designated as normal purchases or normal sales.

Quantitative Disclosures, Balance Sheet Presentation and Income Statement Presentation Related to Derivative Instruments

At December 31, 2013 and 2012 and for the year ended December 31, 2013, 2012 and 2011 the Partnership had no material derivative instruments to disclose.

Credit-Risk Related Contingent Features in Derivative Instruments

In the event Moody's Investors Services or Standard & Poor's Ratings Services were to lower the Partnership's or Enable Oklahoma's senior unsecured debt ratings to a below investment grade rating, the Partnership or Enable Oklahoma would have been required to post no cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position at December 31, 2013. The Partnership or Enable Oklahoma could be required to provide additional credit assurances in future dealings with third parties, which could include letters of credit or cash collateral.

(11) Related Party Transactions

The related party transactions with CenterPoint Energy, OGE Energy and their respective subsidiaries are summarized and described below. There were no material related party transactions with other affiliates.

The Partnership's revenues from affiliated companies accounted for 9%, 14% and 15% of revenues during the year ended December 31, 2013, 2012 and 2011, respectively. Amounts of revenues from affiliated companies included in the Partnership's Combined and Consolidated Statements of Income are summarized as follows:

	December 31,		
	2013	**2012**	**2011**
	(In millions)		
Gas transportation and storage - CenterPoint Energy	$ 108	$ 133	$ 140
Gas sales - CenterPoint Energy	70	—	—
Gas transportation and storage - OGE Energy[(1)]	32	—	—
Gas sales - OGE Energy[(2)]	14	—	—
Total revenues—affiliated companies	$ 224	$ 133	$ 140

(1) The Partnership has contracts with OGE Energy to transport natural gas to OGE Energy's natural gas-fired generation facilities and store natural gas that are reflected in Partnership's Combined and Consolidated Statement of Income beginning on May 1, 2013.

(2) The Partnership sells natural gas to OGE Energy's natural gas-fired generation facilities that are reflected in the Partnership's Combined and Consolidated Statement of Income beginning on May 1, 2013.

Amounts of natural gas purchased from affiliated companies included in the Partnership's Combined and Consolidated Statements of Income are summarized as follows:

	December 31,		
	2013	**2012**	**2011**
	(In millions)		
Cost of goods sold—CenterPoint Energy	$ 4	$ 1	$ 1

The Partnership recorded an expense from OGE Energy of $8 million for the period beginning May 1, 2013 and ended December 31, 2013 for electricity used to power the Partnership's electric compression assets, which is reflected in the Partnership's Combined and Consolidated Statement of Income as operation and maintenance expense beginning on May 1, 2013.

Prior to May 1, 2013, the Partnership had employees and reflected the associated benefit costs directly and not as corporate services. Under the terms of the MFA, effective May 1, 2013 the Partnership's employees were seconded by CenterPoint Energy and OGE Energy, and the Partnership began reimbursing each CenterPoint Energy and OGE Energy for all employee costs under the seconding agreements until terminated with at least 90 days' notice by CenterPoint Energy or OGE Energy, respectively, or by the Partnership. The Partnership intends to identify those seconded employees ("selected employees") to whom it will extend an employment offer during 2014. The Partnership anticipates transitioning the selected employees from CenterPoint Energy and OGE Energy to the Partnership effective January 1, 2015.

Prior to May 1, 2013, the Partnership received certain services and support functions from CenterPoint Energy described below. Under the terms of the MFA, effective May 1, 2013 the Partnership receives services and support functions from CenterPoint Energy and OGE Energy under service agreements for an initial term ending on April 30, 2016. The service agreements automatically extend year-to-year at the end of the initial term, unless terminated by the Partnership with at least 90 days' notice. Additionally, the Partnership may terminate these service agreements at any time with 180 days' notice, if approved by the Board of the General Partner. The Partnership reimburses CenterPoint Energy and OGE Energy for these services up to annual caps, initially $44 million and $30 million, respectively. The Board of Directors of the General Partner has approved 2014 annuals caps of $38 million and $28 million for CenterPoint Energy and OGE Energy, respectively.

The Partnership's operations are dependent on CenterPoint Energy's and OGE Energy's ability to perform under these service agreements, which include certain support functions for accounting, finance, investor relations, planning, legal, communications, governmental and regulatory affairs, and human resources, as well as information technology services and other shared services such as corporate security, facilities management, office support services, and purchasing and logistics. The cost of these services has been charged directly to the Partnership through negotiated usage rates, dedicated asset assignment and proportionate corporate formulas based on operating expenses, assets, gross margin, employees and a composite of assets, gross margin and employees. In some instances, OGE Energy uses the "Distrigas" method to allocate operating costs to the Partnership. The Distrigas method is a three-factor formula that uses an equal weighting of payroll, net operating revenues and gross property, plant and equipment. OGE Energy adopted the Distrigas method in January 1996 as a result of a recommendation by the Staff of the Oklahoma Corporation Commission. CenterPoint Energy uses the Composite Ratio Formula that allocates costs incurred by a service company on behalf of its affiliates to those affiliates. This three-part formula consisting of gross margin, assets, and the number of employees applied 40%, 40% and 20% respectively, attempts to weight various aspects of each of the affiliates so that a fair distribution of the overhead cost is allocated to each affiliate member. These charges are not necessarily indicative of what would have been incurred had the Partnership not been an affiliate of CenterPoint Energy or OGE Energy.

Amounts charged to the Partnership by affiliates for seconded employees and corporate services, included primarily in operating and maintenance expenses in Partnership's Combined and Consolidated Statements of Income are as follows:

	December 31,		
	2013	**2012**	**2011**
	(In millions)		
Seconded Employee Costs—CenterPoint Energy(1)	$ 92	$ —	$ —
Corporate Services—CenterPoint Energy(1)	38	39	37
Seconded Employee Costs—OGE Energy(2)	78	–	–
Corporate Services—OGE Energy(2)	18	–	–
Total corporate services and seconded employee expense	$ 226	$ 39	$ 37

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(1) Beginning on May 1, 2013, CenterPoint Energy assumed all employees of Partnership and seconded such employees to the Partnership. Therefore, costs historically incurred directly by Partnership for employment services are reflected as seconded employee costs subsequent to formation on May 1, 2013.

(2) Corporate services and seconded employee expenses from OGE Energy are reflected in the Statement of Combined and Consolidated Income beginning on May 1, 2013. With respect to the annual cap of $30 million for corporate services, $28 million was incurred during the year ended December 31, 2013, including $10 million prior to the Partnership's acquisition of Enogex on May 1, 2013.

On July 1, 2009, OGE Energy and Enogex entered into hedging transactions to offset natural gas long positions at Enogex with short natural gas exposures at OGE Energy resulting from the cost of generation associated with a wholesale power sales contract. These transactions are for approximately 50,000 million British thermal unit per month from August 2009 to December 2013. These transactions are reflected in the Combined and Consolidated Statement of Income beginning on May 1, 2013.

Until May 1, 2013, the Partnership participated in a "money pool" through which it could borrow or invest with CenterPoint Energy on a short-term basis. Funding needs were aggregated and external borrowing or investing was based on the net cash position. The Partnership's money pool borrowings and investments were reflected in notes payable—affiliated companies and notes receivable—affiliated companies, respectively, in the Combined Balance Sheet as of December 31, 2012.

The notes receivable—affiliated companies as of December 31, 2012 include $434 million and $45 million investments in the money pool and other notes receivable, respectively, and bear an interest rate of 4.869% and 3.25%, respectively. Immediately prior to formation as a limited partnership on May 1, 2013, the Partnership received cash for repayment of the $434 million of investments in the money pool and received a contribution from CenterPoint Energy for the settlement of the $45 million of other notes receivable. Interest income of $9 million, $21 million, and $14 million for the year ended December 31, 2013, 2012 and 2011, respectively, is included in Interest income—affiliated companies.

The Partnership has outstanding short-term and long-term notes payable—affiliated companies to CenterPoint Energy as presented below:

	Year ended December 31,			
	2013		2012	
	Long-Term	Current	Long-Term	Current
Short-term notes payable—affiliated companies:	(In millions)			
Notes payable—affiliated companies [1]	$ —	$ —	$ —	$ 753
Long-term notes payable—affiliated companies:				
Notes payable—affiliated companies[2]	$ 363	$ —	$ 363	$ —
Notes payable—affiliated companies[3]	—	—	646	—
Total long-term notes payable—affiliated companies	$ 363	$ —	$ 1,009	$ —

(1) These notes were payable on demand to CenterPoint Energy. Substantially all of these notes represented the Partnership's money pool borrowings. At December 31, 2012, the Partnership's money pool borrowings had an interest rate of 4.869%. These notes were repaid and terminated immediately prior to formation as a limited partnership on May 1, 2013 without premium or penalty.

(2) These notes are payable to CenterPoint Energy and mature in 2017. Notes having an aggregate principal amount of approximately $273 million bear a fixed interest rate of 2.10% and notes having an aggregate principal amount of approximately $90 million bear a fixed interest rate of 2.45%.

(3) These notes were payable to CenterPoint Energy, bear a fixed interest rate of 6.30% and were scheduled to mature in 2036. These notes were repaid and terminated immediately prior to formation as a limited partnership on May 1, 2013 without premium or penalty.

Prior to repayment of the $753 million and $646 million of short-term and long-term notes payable—affiliated companies, respectively, the Partnership assumed an additional $143 million through a distribution of the Partnership. In total, the repayment of notes payable—affiliated companies immediately prior to formation as a limited partnership on May 1, 2013 was $1.54 billion.

The liabilities recognized upon acquisition of Enogex included $136 million of advances due affiliated companies, payable to OGE Energy. On May 1, 2013, these advances were repaid from proceeds under the Revolving Credit Agreement.

The Partnership recorded affiliated interest expense to CenterPoint Energy of $34 million, $85 million and $90 million during the year ended December 31, 2013, 2012 and 2011, respectively, on notes payable—affiliated companies, which is included in Interest expense on the Combined and Consolidated Statements of Income.

CenterPoint Energy has provided guarantees (Encana and Shell Guarantees) with respect to the performance of certain obligations of the Partnership under long-term gas gathering and treating agreements with an affiliate of Encana Corporation (Encana) and an affiliate of Royal Dutch Shell plc (Shell). As of December 31, 2013, CenterPoint Energy had guaranteed the Partnership's obligations up to an aggregate amount of $100 million under these agreements. Under the terms of the omnibus agreement entered into in connection with the Partnership’s formation as a limited partnership on May 1, 2013, the Partnership and CenterPoint Energy have agreed to use commercially reasonable efforts and cooperate with each other to terminate the Encana and Shell Guarantees, and to release CenterPoint Energy from such guarantees by causing the Partnership or one of its subsidiaries to enter into substitute guarantees or to assume the Encana and Shell Guarantees.

(12) Commitments and Contingencies

(a) Long-TermAgreements

Long-term Gas Gathering and Treating Agreements. The Partnership has long-term agreements with Encana and Shell to provide gathering and treating services for their natural gas production from certain Haynesville Shale and Bossier Shale formations in Texas and Louisiana.

Under the long-term agreements, Encana or Shell may elect to require the Partnership to expand the capacity of its gathering systems by up to an additional 1.3 Bcf per day. The Partnership estimates that the cost to expand the capacity of its gathering systems by an additional 1.3 Bcf per day would be as much as $440 million. Encana and Shell would provide incremental volume commitments in connection with an election to expand system capacity.

Long-term Agreement with Exxon. In March 2013, Enable Bakken entered into a long-term agreement with an affiliate of Exxon-Mobil Corporation (Exxon), to provide gathering services for certain of Exxon’s crude oil production through a new crude oil gathering and transportation pipeline system in North Dakota’s liquids-rich Bakken shale. The agreement with Exxon was entered into pursuant to the open season announced by Enable Bakken in February 2013. Under the terms of the agreement, which includes volume commitments, Enable Bakken will provide service to Exxon over a gathering system to be constructed by Enable Bakken in Dunn and McKenzie counties in North Dakota with a capacity of up to 19,500 barrels per day. Certain portions of the pipeline system were placed in service in 2013 with the remaining portions to be placed in service in the third quarter of 2014. As of December 31, 2013, the Partnership estimates the remaining construction costs to be $17 million.

Operating Lease Obligations. The Partnership has operating lease obligations expiring at various dates. Future minimum payments for noncancellable operating leases are as follows:

Year ended December 31 (In millions)	2014	2015	2016	2017	2018	After 2018	Total
Noncancellable operating leases	$ 7	$ 5	$ 2	$ 1	$ —	$ —	$ 15

Total rental expense for all operating leases was $12 million, $16 million and $26 million in 2013, 2012 and 2011, respectively.

The Partnership currently occupies 134,219 square feet of office space at its executive offices under a lease that expires March 31, 2017. The lease payments are $11 million over the lease term, which began April 1, 2012. This lease has rent escalations which increase after 5 and 10 years if the lease is renewed. These lease expenses are reflected in the Statement of Combined or Consolidated Income beginning on May 1, 2013.

The Partnership currently has 23 compression service agreements, of which three agreements are on a month-to-month basis, three agreements will expire in 2014, 17 agreements will expire in 2015 and 2 agreements will expire in 2016. The Partnership also has 8 gas treating agreements, of which 6 agreements are on a month-to-month basis, one agreement will expire in 2013 and one agreement will expire in 2014. These lease expenses are reflected in the Statement of Combined or Consolidated Income beginning on May 1, 2013.

Other Purchase Obligations and Commitments. In 2004, Enable Oklahoma entered into a firm transportation service agreement with Cheyenne Plains, who operates the Cheyenne Plains Pipeline that provides firm transportation services in Wyoming, Colorado and Kansas, for 60,000 dekatherms/day of firm capacity on the pipeline. The firm transportation service agreement was for a 10-year term beginning with the in-service date of the Cheyenne Plains Pipeline in March 2005 with an annual demand fee of $7 million. Effective March 1, 2007, Enable Oklahoma and Cheyenne Plains amended the firm transportation service agreement to provide for Enable Oklahoma to turn back 20,000 dekatherms/day of its capacity beginning in January 2008 for the remainder of the term.

In 2006, Enable Oklahoma entered into a firm capacity agreement with Midcontinent Express Pipeline (MEP) for a primary term of 10 years (subject to possible extension) that gives MEP and its shippers' access to capacity on Enable Oklahoma's system. The quantity of capacity subject to the MEP capacity agreement is currently 272 MMcf/d, with the quantity subject to being increased by mutual agreement pursuant to the capacity agreement. In 2009, Enable Oklahoma entered into a firm transportation service agreement with MEP for 10,000 dekatherms/day of firm capacity on the pipeline. The firm transportation service agreement was for a five-year term beginning with the in-service date of the MEP pipeline in June 2009 with an annual demand fee of $2 million.

The Partnership's other future purchase obligations and commitments estimated for the next five years are as follows:

Year ended December 31 (In millions)	2014	2015	2016	2017	2018	Total
Other purchase obligations and commitments	$ 11	$ 4	$ 1	$ —	$ —	$ 16

(b) Legal, Regulatory and Other Matters

Regulatory Matters

MRT Rate Case. MRT, a subsidiary of the Partnership, made a rate filing with the FERC pursuant to Section 4 of the Natural Gas Act, on August 22, 2012 that became effective March 1, 2013, following a five-month suspension, in which it requested an annual cost of service of $104 million (an increase of approximately $47 million above the annual cost of service underlying the current FERC approved maximum rates for MRT's pipeline). On July 30, 2013, MRT filed with the FERC an uncontested Stipulation and Agreement and Offer of Settlement, resolving all issues in the rate case. The settlement specifies few particulars, other than setting an annual overall cost-of-service for MRT of $84 million and increasing the depreciation rates for certain asset classes. In September 2013, the FERC approved the settlement. Although the settlement became effective November 1, 2013, the settlement rates are effective as of March 1, 2013. As a result, in the fourth quarter of 2013 MRT made refunds to certain of its customers totaling approximately $6 million, which amounts had previously been reserved.

2013 Fuel Filing. On March 1, 2013, Enable Oklahoma submitted its annual fuel filing to establish the fixed fuel percentages for its East Zone and West Zone for the upcoming fuel year (April 1, 2013 through March 31, 2014).

The deadline for interventions and protests on the filing was March 18, 2013 and no protests were filed. On June 25, 2013, the FERC accepted Enable Oklahoma's proposed zonal fuel percentages.

Other Proceedings

The Partnership is involved in other legal, environmental, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business. Some of these proceedings involve substantial amounts. The Partnership regularly analyzes current information and, as necessary, provides accruals for probable liabilities on the eventual disposition of these matters. The Partnership does not expect the disposition of these matters to have a material adverse effect on its financial condition, results of operations or cash flows.

(13) Income Taxes

Prior to May 1, 2013, the Partnership was included in the consolidated income tax returns of CenterPoint Energy. The Partnership calculated its income tax provision on a separate return basis under a tax sharing agreement with CenterPoint Energy.

Upon conversion to a limited partnership on May 1, 2013, the Partnership's earnings are no longer subject to income tax (other than Texas state margin taxes) and are taxable at the individual partner level. The Partnership and its subsidiaries are pass-through entities for federal income tax purposes. See Note 1 for further discussion of the conversion to a limited partnership. For these entities, all income, expenses, gains, losses and tax credits generated flow through to their owners and, accordingly, do not result in a provision for income taxes in the financial statements, (other than Texas state margin taxes). Consequently, the Combined and Consolidated Statements of Income do not include an income tax provision for income earned on or after May 1, 2013 (other than Texas state margin taxes).

The items comprising income tax expense are as follows:

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Provision (benefit) for current income taxes:			
Federal	$ 1	$ 6	$ (20)
State	1	1	7
Total Provision (benefit) current income taxes	2	7	(13)
Provision (benefit) for deferred income taxes, net:			
Federal	(1,039)	164	146
State	(155)	32	30
Total provision (benefit) for deferred income taxes, net	(1,194)	196	176
Total income tax expense (benefit)	$ (1,192)	$ 203	$ 163

The following schedule reconciles the statutory Federal tax rate to the effective income tax rate:

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Income before income taxes	$ 426	$ 519	$ 395
Federal statutory rate	35 %	35%	35%
Expected federal income tax expense	149	182	138
Increase in tax expense resulting from:			
State income taxes, net of federal income tax	8	21	24
Income not subject to tax	(103)	—	—
Conversion to partnership	(1,240)	—	—
Other, net	(6)	—	1
Total	(1,341)	21	25
Total income tax expense (benefit)	$ (1,192)	$ 203	$ 163
Effective tax rate	(275.9)%	39.1%	41.2%

As a result of the conversion to a partnership, CenterPoint Energy assumed all outstanding current income tax liabilities and the deferred income tax assets and liabilities were eliminated by recording a provision for income tax benefit equal to $1.24 billion. Therefore, there were no federal deferred income tax assets and liabilities balances at December 31, 2013. The components of Deferred Income Taxes as of December 31, 2013 and 2012 were as follows:

	December 31,	
	2013	2012
	(In millions)	
Deferred tax assets:		
Current:		
Deferred gas costs	$ —	$ 29
Other	—	2
Total current deferred tax assets	—	31
Non-current:		
Employee benefits	—	11
Net operating loss carryforwards	—	8
Other	—	7
Total non-current deferred tax assets	—	26
Total deferred tax assets	—	57
Deferred tax liabilities:		
Non-current:		
Depreciation	8	1,219
Other	—	79
Total non-current deferred tax liabilities	8	1,298
Accumulated deferred income taxes, net	$ 8	$ 1,241

Tax Attribute Carryforwards and Valuation Allowance. At December 31, 2012, the Partnership had approximately $5 million of federal net operating loss carryforwards which begin to expire in 2031 and $120 million of state net operating loss carryforwards which expire in various years between 2013 and 2032. At December 31, 2012 the Partnership expected to realize the benefit of its deferred tax assets before expiration and as a result there was no valuation allowance at December 31, 2012. As a result of the conversion to a partnership, the federal and state net operating losses were distributed to CenterPoint Energy as part of a deemed liquidation for tax purposes on May 1, 2013. Accordingly, there were no remaining carryforwards available to the Partnership as of December 31, 2013.

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

	December 31,		
	2013	2012	2011
	(In millions)		
Balance, beginning of year	$ —	$ 3	$ 5
Tax Positions related to prior years:			
Reductions	—	(3)	(2)
Balance, end of year	$ —	$ —	$ 3

The Partnership's unrecognized tax benefits on uncertain tax positions would not affect the effective income tax rate if they were recognized. The Partnership recognizes interest and penalties as a component of income tax expense. There was no unrecognized tax benefit as of December 31, 2013 and 2012. The Partnership recognized approximately $-0- million, $1 million of income tax benefit, and less than $1 million of income tax expense related to the Partnership's interest on uncertain income tax positions during the year ended December 31, 2013, 2012 and 2011 respectively. The Partnership accrued no interest on uncertain income tax positions related to the Partnership at December 31, 2013 and 2012.

Tax Audits and Settlements. CenterPoint Energy's consolidated federal income tax returns have been audited by the IRS and settled through the 2011 tax year. CenterPoint Energy is currently under examination by the IRS for tax year 2012. The Partnership considered the effect of this examination in its accrual for settled issues and liability for uncertain income tax positions as of December 31, 2013.

(14) Reportable Business Segments

The Partnership's determination of reportable business segments considers the strategic operating units under which it manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments. The accounting policies of the business segments are the same as those described in the summary of significant accounting described in Note 1. Some executive benefit costs of Partnership, incurred prior to May 1, 2013 have not been allocated to business segments. The Partnership uses operating income as the measure of profit or loss for its business segments.

The Partnership's assets and operations are organized into two business segments: (i) Gathering and Processing, which primarily provides natural gas and crude oil gathering, processing and fractionation services for our 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. Effective May 1, 2013, the intrastate natural gas pipeline operations acquired from Enogex were combined with the interstate pipelines in the Transportation and Storage segment and the non-rate regulated natural gas gathering, processing and treating operations acquired from Enogex were combined within the Gathering and Processing segment.

During the integration of the operations acquired from Enogex, the intrastate natural gas pipelines and non- rate regulated natural gas gathering, processing and treating operations have been identified as separate operating segments, which are aggregated with the respective interstate pipelines and legacy gathering and processing operations as the respective (1) Transportation and Storage and (2) Gathering and Processing reportable segments.

Financial data for business segments and services are as follows:

Year Ended December 31, 2013	Gathering and Processing(1)	Transportation and Storage(2)	Eliminations	Total
		(In millions)		
Operating revenues(3)(4)	$ 1,740	$ 1,149	$ (400)	$ 2,489
Cost of goods sold	1,075	636	(398)	1,313
Operation and maintenance	222	209	(2)	429
Depreciation and amortization	117	95	—	212
Impairment	12	—	—	12
Taxes other than income	20	34	—	54
Operating income	$ 294	$ 175	$ —	$ 469
Total assets	$ 7,157	$ 5,717	$ (1,642)	$ 11,232
Capital expenditures	$ 431	$ 142	$ —	$ 573

Year Ended December 31, 2012	Gathering and Processing(1)	Transportation and Storage(2)	Eliminations	Total
		(In millions)		
Operating revenues(3)(4)	$ 502	$ 502	$ (52)	$ 952
Cost of goods sold	124	55	(50)	129
Operation and maintenance	114	155	(2)	267
Depreciation and amortization	50	56	—	106
Taxes other than income	5	29	—	34
Operating income	$ 209	$ 207	$ —	$ 416
Total assets	$ 2,439	$ 4,052	$ (9)	$ 6,482
Capital expenditures	$ 70	$ 132	$ —	$ 202

Year Ended December 31, 2011	Gathering and Processing(1)	Transportation and Storage(2)	Eliminations	Total
		(In millions)		
Operating revenues(3)(4)	$ 415	$ 553	$ (36)	$ 932
Cost of goods sold	70	65	(34)	101
Operation and maintenance	111	154	(2)	263
Depreciation and amortization	37	54	—	91
Taxes other than income	5	32	—	37
Operating income	$ 192	$ 248	$ —	$ 440
Total assets	$ 1,933	$ 3,869	$ (6)	$ 5,796
Capital expenditures	$ 248	$ 98	$ —	$ 346

(1) Gathering and processing recorded equity income of $-0-, $5 million and $10 million for the year ended December 31, 2013, 2012 and 2011, respectively, from its 50% interest in a jointly-owned gas processing plant, Waskom. These amounts are included in Equity in earnings of equity method affiliates under the Other income (expense) caption. The Partnership consolidated Waskom during the third quarter of 2012. See Note 7 for further discussion regarding Waskom.

(2) Transportation and storage recorded equity income of $15 million, $26 million and $21 million for the year ended December 31, 2013, 2012 and 2011 respectively, from its interest in SESH, a jointly-owned pipeline. These amounts are included in Equity in earnings of equity method affiliates under the Other

Income (Expense) caption. Transportation and Storage's investment in SESH was $198 million, $404 million as of December 31, 2013 and 2012, respectively, and is included in Investments in equity method affiliates. The Partnership reflected a 50% interest in SESH until May 1, 2013 when the Partnership distributed a 25.05% interest in SESH to CenterPoint Energy. See Note 7 for further discussion regarding SESH.

(3) Revenues are comprised of gathering, processing, transportation and storage revenues.

(4) The Partnership had no external customers accounting for 10% or more of revenues in periods shown. See Note 11 for revenues from affiliated companies.

(15) Subsequent Events

On February 14, 2014, the Partnership distributed $114 million to the unitholders of record as of January 1, 2014.