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, 2014

or

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

Commission File No. 1-2921

PANHANDLE EASTERN PIPE LINE COMPANY, LP
(Exact name of registrant as specified in its charter)

Delaware	**44-0382470**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

3738 Oak Lawn Avenue, Dallas, Texas 75219
(Address of principal executive offices) (zip code)

(214) 981-0700
(Registrant’s telephone number, including area code)

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

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

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 x No ☐

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

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

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 the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer x Smaller reporting company ☐

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

Panhandle Eastern Pipe Line Company, LP meets the conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format. Items 1, 2 and 7 have been reduced and Items 6, 10, 11, 12 and 13 have been omitted in accordance with Instruction I.

PANHANDLE EASTERN PIPE LINE COMPANY, LP

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Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Panhandle Eastern Pipe Line Company LP, and its subsidiaries ("Panhandle" or the "Company") in periodic press releases and some oral statements of Panhandle officials during presentations about the Company, include forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Statements using words such as "anticipate," "project," "expect," "plan," "goal," "forecast," "estimate," "intend," "continue," "believe," "may," "will" or similar expressions help identify forward-looking statements. Although the Company believes such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that such assumptions, expectations or projections will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, the Company's actual results may vary materially from those anticipated, estimated or expressed, forecasted, projected or expected in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks that are difficult to predict and beyond management's control. For additional discussion of risks, uncertainties and assumptions, see "Part I – Item 1A. Risk Factors" included in this annual report.

Definitions

The abbreviations, acronyms and industry terminology used in this annual report on Form 10-K are defined as follows:

/d	per day
ARO	Asset retirement obligation
Bcf	Billion cubic feet
Btu	British thermal units
Citrus	Citrus, LLC
CrossCountry	CrossCountry Energy, LLC
EPA	United States Environmental Protection Agency
ETC	La Grange Acquisition, L.P., a wholly-owned subsidiary of ETP, which conducts business under the assumed named of Energy Transfer Company
ETE	Energy Transfer Equity, L.P.
ETP	Energy Transfer Partners, L.P., a subsidiary of ETE
ETP Holdco	ETP Holdco Corporation, the entity formed by ETP and ETE in 2012 to own the equity interests in Southern Union and Sunoco, Inc.
Exchange Act	Securities Exchange Act of 1934
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States of America
Lake Charles LNG	Lake Charles LNG Company, LLC
LIBOR	London Interbank Offered Rate
LNG	Liquefied natural gas
LNG Holdings	Trunkline LNG Holdings, LLC
MGE	Missouri Gas Energy
NEG	New England Gas Company
NGL	Natural gas liquids
OPEB plans	Other postretirement employee benefit plans
Panhandle	PEPL and its subsidiaries

PCBs	Polychlorinated biphenyls
PEPL	Panhandle Eastern Pipe Line Company, LP
PEPL Holdings	PEPL Holdings, LLC
PRPs	Potentially responsible parties
Regency	Regency Energy Partners LP, a subsidiary of ETE
Sea Robin	Sea Robin Pipeline Company, LLC
SEC	United States Securities and Exchange Commission
Southern Union	Southern Union Company
Southwest Gas	Pan Gas Storage, LLC (d.b.a. Southwest Gas)
SUGS	Southern Union Gas Services
TBtu	Trillion British thermal units
Trunkline	Trunkline Gas Company, LLC

PART I

ITEM 1. BUSINESS

OUR BUSINESS

Introduction

Panhandle, a Delaware limited partnership, is a wholly-owned subsidiary of SUG Holding Company. SUG Holding Company is a wholly-owned subsidiary of ETP Holdco, which is wholly-owned by ETP. References to "we," "us," "our", the "Company" and "Panhandle" shall mean Panhandle Eastern Pipe Line Company, LP and its subsidiaries. The Company is primarily engaged in the transportation and storage of natural gas and is subject to the rules and regulations of the FERC. Panhandle directly or indirectly owns all of the equity interests in Trunkline, Sea Robin and Southwest Gas, among other subsidiaries.

On January 10, 2014, the Company consummated a merger with Southern Union, the indirect parent of the Company at the time, and PEPL Holdings, the sole limited partner of the Company, pursuant to which each of Southern Union and PEPL Holdings were merged with and into the Company, with the Company surviving the merger. The assets and liabilities of Southern Union and PEPL Holdings, collectively, that were assumed by the Company included the following:

- 2.2 million ETP common units;
- 31.4 million Regency common units and 6.3 million Regency Class F Units;
- Approximately $176 million of Southern Union third party long-term debt and $1.09 billion of notes payable to ETP; and
- Guarantee of $600 million of Regency senior notes.

On February 19, 2014, Panhandle transferred to ETP all of the interests in Lake Charles LNG, the entity that owns a LNG regasification facility in Lake Charles, Louisiana, in exchange for the cancellation of a $1.09 billion note payable to ETP that was assumed by the Company in the merger with Southern Union on January 10, 2014. Also on February 19, 2014, ETE and ETP completed the transfer to ETE of Lake Charles LNG from ETP in exchange for the redemption by ETP of 18.7 million ETP common units held by ETE. The transaction was effective as of January 1, 2014.

Lake Charles LNG was previously named Trunkline LNG Company, LLC, and changed its name in September 2014 to Lake Charles LNG Company, LLC. All references to this company throughout this document reflect the new name of the company, regardless of whether the disclosure relates to periods or events prior to the dates of the name change.

See Note 3 to our consolidated financial statements for information related to these transactions.

Asset Overview

The Company owns and operates a large natural gas open-access interstate pipeline network. The pipeline network, consisting of the PEPL, Trunkline and Sea Robin transmission systems, serves customers in the Midwest, Gulf Coast and Midcontinent United States with a comprehensive array of transportation and storage services. PEPL's transmission system consists of four large diameter pipelines extending approximately 1,300 miles from producing areas in the Anadarko Basin of Texas, Oklahoma and Kansas through Missouri, Illinois, Indiana, Ohio and into Michigan. Trunkline's transmission system consists of two large diameter pipelines extending approximately 1,400 miles from the Gulf Coast areas of Texas and Louisiana through Arkansas, Mississippi, Tennessee, Kentucky, Illinois, Indiana and to Michigan. Sea Robin's transmission system consists of two offshore Louisiana natural gas supply systems extending approximately 120 miles into the Gulf of Mexico. In connection with its natural gas pipeline transmission and storage systems, the Company has five natural gas storage fields located in Illinois, Kansas, Louisiana, Michigan and Oklahoma. Southwest Gas operates four of these fields and Trunkline operates one.

Panhandle earns most of its revenue by entering into firm transportation and storage contracts, providing capacity for customers to transport and store natural gas in its facilities. The Company provides firm transportation services under contractual arrangements to local distribution company customers and their affiliates, natural gas marketers, producers, other pipelines, electric power generators and a variety of end-users. The Company's pipelines offer both firm and interruptible transportation to customers on a short-term and long-term basis. Demand for natural gas transmission on the Company's pipeline systems peaks during the winter months, with the highest throughput and a higher portion of annual total operating revenues occurring during the first and fourth calendar quarters. Average reservation revenue rates realized by the Company are dependent on certain factors, including but not limited to rate regulation, customer demand for capacity, and capacity sold for a given period and, to an extent, utilization of capacity. Commodity or utilization revenues, which are more variable in nature, are dependent upon a number of factors including weather, storage levels and pipeline capacity availability levels, and customer demand for firm and interruptible services, including parking services. The majority of Panhandle's revenues are related to firm capacity reservation charges, of which reservation charges accounted for approximately 83% of total revenues in 2014.

The following table provides a summary of pipeline transportation (including deliveries made throughout the Company's pipeline network) in TBtu:

	Year Ended December 31,	
	2014	2013
PEPL transportation	625	613
Trunkline transportation	694	722
Sea Robin transportation	130	141

The following table provides a summary of certain statistical information associated with the Company at December 31, 2014:

Approximate Miles of Pipelines	
PEPL	6,000
Trunkline	3,000
Sea Robin	1,000
Peak Day Delivery Capacity (Bcf/d)	
PEPL	2.8
Trunkline	1.7
Sea Robin	2.3
Underground Storage Capacity-Owned (Bcf)	68.1
Underground Storage Capacity-Leased (Bcf)	33.3
Approximate Number of Transportation Customers	500
Weighted Average Remaining Life in Years of Firm Transportation Contracts (1)	
PEPL	3.8
Trunkline	7.8
Sea Robin (2)	N/A
Weighted Average Remaining Life in Years of Firm Storage Contracts (1)	
PEPL	7.1
Trunkline	4.0

(1) Weighted by firm capacity volumes.

(2) Sea Robin's contracts are primarily interruptible, with only four firm contracts in place.

Regulation

The Company is subject to regulation by various federal, state and local governmental agencies, including those specifically described below.

FERC has comprehensive jurisdiction over PEPL, Trunkline, Sea Robin and Southwest Gas. In accordance with the Natural Gas Act of 1938, FERC's jurisdiction over natural gas companies encompasses, among other things, the acquisition, operation and disposition of assets and facilities, the services provided and rates charged.

FERC has authority to regulate rates and charges for transportation and storage of natural gas in interstate commerce. FERC also has authority over the construction and operation of pipeline and related facilities utilized in the transportation and sale of natural gas in interstate commerce, including the extension, enlargement or abandonment of service using such facilities. PEPL, Trunkline, Sea Robin and Southwest Gas hold certificates of public convenience and necessity issued by FERC, authorizing them to operate the pipelines, facilities and properties now in operation and to transport and store natural gas in interstate commerce.

The Company is also subject to the Natural Gas Pipeline Safety Act of 1968 and the Pipeline Safety Improvement Act of 2002, which regulate the safety of natural gas pipelines.

For additional information regarding the Company's regulation and rates, see "Item 1. Business – Environmental", "Item 1A. Risk Factors" and Note 14 to our consolidated financial statements.

Competition

The interstate pipeline and storage systems of the Company compete with those of other interstate and intrastate pipeline companies in the transportation and storage of natural gas. The principal elements of competition among pipelines are rates, terms of service, flexibility and reliability of service.

Natural gas competes with other forms of energy available to the Company's customers and end-users, including electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability or price of natural gas and other forms of energy, the level of business activity, conservation, legislation and governmental regulation, the capability to convert to alternate fuels and other factors, including weather and natural gas storage levels, affect the ongoing demand for natural gas in the areas served by the Company. In order to meet these challenges, the Company will need to adapt its marketing strategies, the types of transportation and storage services provided and its pricing and rates to address competitive forces. In addition, FERC may authorize the construction of new interstate pipelines that compete with the Company's existing pipelines.

OTHER MATTERS

Environmental

The Company is subject to federal, state and local laws and regulations regarding water quality, hazardous and solid waste management, air quality control and other environmental matters. These laws and regulations require the Company to conduct its operations in a specified manner and to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with environmental requirements may expose the Company to significant fines, penalties and/or interruptions in operations. The Company's environmental policies and procedures are designed to achieve compliance with such laws and regulations. These evolving laws and regulations and claims for damages to property, employees, other persons and the environment resulting from current or past operations may result in significant expenditures and liabilities in the future. The Company engages in a process of updating and revising its procedures for the ongoing evaluation of its operations to identify potential environmental exposures and enhance compliance with regulatory requirements. For additional information concerning the impact of environmental regulation on the Company, see "Item 1A. Risk Factors" and Note 14 to our consolidated financial statements.

Employees

At January 30, 2015, the Company had 562 employees. Of these employees, 211 were represented by the United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial, and Service Workers International AFL-CIO, CLC. The current union contract expires on May 29, 2016.

SEC Reporting

We file or furnish annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any related amendments and supplements thereto with the SEC. You may read and copy any materials we file or furnish with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information regarding the Public Reference Room by calling the SEC at 1-800-732-0330. In addition, the SEC maintains an internet website at http://www.sec.gov that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

We provide electronic access, free of charge, to our periodic and current reports on our internet website located at http://www.energytransfer.com. These reports are available on our website as soon as reasonably practicable after we electronically file such materials with the SEC. Information contained on our website is not part of this report.

ITEM 1A. RISK FACTORS

The risks and uncertainties described below are not the only ones faced by the Company. Additional risks and uncertainties that the Company is unaware of, or that it currently deems immaterial, may become important factors that affect it. If any of the following risks occurs, the Company's business, financial condition, results of operations or cash flows could be materially and adversely affected.

Risks That Relate to the Company

The Company has substantial debt and may not be able to obtain funding or obtain funding on acceptable terms because of deterioration in the credit and capital markets. This may hinder or prevent the Company from meeting its future capital needs.

The Company has a significant amount of debt outstanding. As of December 31, 2014, consolidated debt on the consolidated balance sheets totaled $1.19 billion outstanding.

Covenants exist in certain of the Company's debt agreements that require the Company to maintain a fixed charge coverage ratio, a leverage ratio and to meet certain ratios of earnings before depreciation, interest and taxes to cash interest expense. A failure by the Company to satisfy any such covenant would give rise to an event of default under the associated debt, which could become immediately due and payable if the Company did not cure such default within any permitted cure period or if the Company did not obtain amendments, consents or waivers from its lenders with respect to such covenants. Any such acceleration or inability to borrow could cause a material adverse change in the Company's financial condition.

The Company relies on access to both short- and long-term credit as a significant source of liquidity for capital requirements not satisfied by the cash flow from its operations. Deterioration in the Company's financial condition could hamper its ability to access the capital markets.

Global financial markets and economic conditions have been, and may continue to be, disrupted and volatile. The current weak economic conditions have made, and may continue to make, obtaining funding more difficult.

Due to these factors, the Company cannot be certain that funding will be available if needed and, to the extent required, on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, the Company may be unable to grow its existing business, complete acquisitions, refinance its debt or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on the Company's revenues and results of operations.

Credit ratings downgrades could increase the Company's financing costs and limit its ability to access the capital markets.

The Company is not party to any lending agreement that would accelerate the maturity date of any obligation due to a failure to maintain any specific credit rating, nor would a reduction in any credit rating, by itself, cause an event of default under any of the Company's lending agreements. However, if its current credit ratings were downgraded below investment grade, the Company could be negatively impacted as follows:

- Borrowing costs associated with existing debt obligations could increase in the event of a credit rating downgrade;
- The costs of refinancing debt that is maturing or any new debt issuances could increase due to a credit rating downgrade; and
- FERC may be unwilling to allow the Company to pass along increased debt service costs to natural gas customers.

The Company's credit rating can be impacted by the credit rating and activities of its parent company. Thus, adverse impacts to ETP and its activities, which may include activities unrelated to the Company, may have adverse impacts on the Company's credit rating and financing and operating costs.

The financial soundness of the Company's customers could affect its business and operating results and the Company's credit risk management may not be adequate to protect against customer risk.

As a result of macroeconomic challenges that have impacted the economy of the United States and other parts of the world, the Company's customers may experience cash flow concerns. As a result, if customers' operating and financial performance deteriorates, or if they are unable to make scheduled payments or obtain credit, customers may not be able to pay, or may delay payment of, accounts receivable owed to the Company. The Company's credit procedures and policies may not be adequate to fully eliminate customer credit risk. In addition, in certain situations, the Company may assume certain additional credit risks for competitive reasons or otherwise. Any inability of the Company's customers to pay for services could adversely affect the Company's financial condition, results of operations and cash flows.

The Company depends on distributions from its subsidiaries to meet its needs.

The Company is dependent on the earnings and cash flows of, and dividends, loans, advances or other distributions from, its subsidiaries to generate the funds necessary to meet its obligations. The availability of distributions from such entities is subject to their earnings and capital requirements, the satisfaction of various covenants and conditions contained in financing documents by which they are bound or in their organizational documents, and in the case of the regulated subsidiaries, regulatory restrictions that limit their ability to distribute profits to the Company.

The Company is controlled by ETP.

The Company is an indirect wholly-owned subsidiary of ETP. ETP executives serve as the board of managers and as executive officers of the Company. Accordingly, ETP controls and directs all of the Company’s business affairs, decides all matters submitted for member approval and may unilaterally effect changes to its management team. In circumstances involving a conflict of interest between ETP, on the one hand, and the Company’s creditors, on the other hand, the Company can give no assurance that ETP would not exercise its power to control the Company in a manner that would benefit ETP to the detriment of the Company’s creditors.

Some of our executive officers and directors face potential conflicts of interest in managing our business.

Certain of our executive officers and directors are also officers and/or directors of ETE and/or ETP. These relationships may create conflicts of interest regarding corporate opportunities and other matters. The resolution of any such conflicts may not always be in our or our creditors’ best interests. In addition, these overlapping executive officers and directors allocate their time among us and ETE and/or ETP. These officers and directors face potential conflicts regarding the allocation of their time, which may adversely affect our business, results of operations and financial condition.

Our affiliates may compete with us.

Our affiliates and related parties are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us.

The Company’s growth strategy entails risk.

The Company may actively pursue acquisitions in the energy industry to complement and diversify its existing businesses. As part of its growth strategy, Panhandle may:

- examine and potentially acquire regulated or unregulated businesses, including transportation and storage assets and gathering and processing businesses within the natural gas industry;
- enter into joint venture agreements and/or other transactions with other industry participants or financial investors;
- selectively divest parts of its business, including parts of its core operations; and
- continue expanding its existing operations.

The Company’s ability to acquire new businesses will depend upon the extent to which opportunities become available, as well as, among other things:

- its success in valuing and bidding for the opportunities;
- its ability to assess the risks of the opportunities;
- its ability to obtain regulatory approvals on favorable terms; and
- its access to financing on acceptable terms.

Once acquired, the Company’s ability to integrate a new business into its existing operations successfully will largely depend on the adequacy of implementation plans, including the ability to identify and retain employees to manage the acquired business, and the ability to achieve desired operating efficiencies. The successful integration of any businesses acquired in the future may entail numerous risks, including:

- the risk of diverting management’s attention from day-to-day operations;
- the risk that the acquired businesses will require substantial capital and financial investments;
- the risk that the investments will fail to perform in accordance with expectations; and
- the risk of substantial difficulties in the transition and integration process.

These factors could have a material adverse effect on the Company’s business, financial condition, results of operations and cash flows, particularly in the case of a larger acquisition or multiple acquisitions in a short period of time.

The consideration paid in connection with an investment or acquisition also affects the Company's financial results. In addition, acquisitions or expansions may result in the incurrence of additional debt.

The Company is subject to operating risks.

The Company's operations are subject to all operating hazards and risks incident to handling, storing, transporting and providing customers with natural gas, including adverse weather conditions, explosions, pollution, release of toxic substances, fires and other hazards, each of which could result in damage to or destruction of its facilities or damage to persons and property. If any of these events were to occur, the Company could suffer substantial losses. Moreover, as a result, the Company has been, and likely will be, a defendant in legal proceedings and litigation arising in the ordinary course of business. While the Company maintains insurance against many of these risks to the extent and in amounts that it believes are reasonable, the Company's insurance coverages have significant deductibles and self-insurance levels, limits on maximum recovery, and do not cover all risks. There is also the risk that the coverages will change over time in light of increased premiums or changes in the terms of the insurance coverages that could result in the Company's decision to either terminate certain coverages, increase deductibles and self-insurance levels, or decrease maximum recoveries. In addition, there is a risk that the insurers may default on their coverage obligations. As a result, the Company's results of operations, cash flows or financial condition could be adversely affected if a significant event occurs that is not fully covered by insurance.

Terrorist attacks aimed at our facilities could adversely affect our business, results of operations, cash flows and financial condition.

The United States government has issued warnings that energy assets, including the nation's pipeline infrastructure, may be the future target of terrorist organizations. Some of our facilities are subject to standards and procedures required by the Chemical Facility Anti-Terrorism Standards. We believe we are in compliance with all material requirements; however, such compliance may not prevent a terrorist attack from causing material damage to our facilities or pipelines. Any such terrorist attack on our facilities or pipelines, those of our customers, or in some cases, those of other pipelines could have a material adverse effect on our business, financial condition and results of operations.

The impact that terrorist attacks, such as the attacks of September 11, 2001, may have on the energy industry in general, and on the Company in particular, is not known at this time. Uncertainty surrounding military activity may affect the Company's operations in unpredictable ways, including disruptions of fuel supplies and markets and the possibility that infrastructure facilities, including pipelines, gathering facilities and processing plants, could be direct targets of, or indirect casualties of, an act of terror or a retaliatory strike. The Company may have to incur significant additional costs in the future to safeguard its physical assets.

Cybersecurity breaches and other disruptions could compromise our information and expose us to liability, which would cause our business and reputation to suffer.

In the ordinary course of our business, we collect and store sensitive data, including intellectual property, our proprietary business information and that of our customers, suppliers and business partners, and personal identification information of our employees, in our data centers and on our networks. The secure processing, maintenance and transmission of this information is critical to our operations and business strategy. Despite our security measures, our information technology and infrastructure may be vulnerable to attacks by hackers or breached due to employee error, malfeasance or other disruptions. Any such breach could compromise our networks and the information stored there could be accessed, publicly disclosed, lost or stolen. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties, disruption of our operations, damage to our reputation, and cause a loss of confidence in our products and services, which could adversely affect our business.

Our operations could be disrupted if our information systems fail, causing increased expenses and loss of sales.

Our business is highly dependent on financial, accounting and other data processing systems and other communications and information systems, including our enterprise resource planning tools. We process a large number of transactions on a daily basis and rely upon the proper functioning of computer systems. If a key system was to fail or experience unscheduled downtime for any reason, even if only for a short period, our operations and financial results could be affected adversely. Our systems could be damaged or interrupted by a security breach, fire, flood, power loss, telecommunications failure or similar event. We have a formal disaster recovery plan in place, but this plan may not entirely prevent delays or other complications that could arise from an information systems failure. Our business interruption insurance may not compensate us adequately for losses that may occur.

Security breaches and other disruptions could compromise our information and operations, and expose us to liability, which would cause our business and reputation to suffer.

In the ordinary course of our business, we collect and store sensitive data, including intellectual property, our proprietary business information and that of our customers, suppliers and business partners, and personally identifiable information of our employees, in our data centers and on our networks. The secure processing, maintenance and transmission of this information is critical to our operations and business strategy. Despite our security measures, our information technology and infrastructure may be vulnerable to attacks by hackers or breached due to employee error, malfeasance or other disruptions. Any such breach could compromise our networks and the information stored there could be accessed, publicly disclosed, lost or stolen. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties for divulging shipper information, disruption of our operations, damage to our reputation, and loss of confidence in our products and services, which could adversely affect our business.

Our information technology infrastructure is critical to the efficient operation of our business and essential to our ability to perform day-today operations. Breaches in our information technology infrastructure or physical facilities, or other disruptions, could result in damage to our assets, safety incidents, damage to the environment, potential liability or the loss of contracts, and have a material adverse effect on our operations, financial position and results of operations.

The success of the pipeline business depends, in part, on factors beyond the Company's control.

Third parties own most of the natural gas transported and stored through the pipeline systems operated by the Company. As a result, the volume of natural gas transported and stored depends on the actions of those third parties and is beyond the Company's control. Further, other factors beyond the Company's and those third parties' control may unfavorably impact the Company's ability to maintain or increase current transmission and storage rates, to renegotiate existing contracts as they expire or to remarket unsubscribed capacity. High utilization of contracted capacity by firm customers reduces capacity available for interruptible transportation and parking services.

The expansion of the Company's pipeline systems by constructing new facilities subjects the Company to construction and other risks that may adversely affect the financial results of the pipeline businesses.

The Company may expand the capacity of its existing pipeline and storage facilities by constructing additional facilities. Construction of these facilities is subject to various regulatory, development and operational risks, including:

- the Company's ability to obtain necessary approvals and permits from FERC and other regulatory agencies on a timely basis and on terms that are acceptable to it;
- the ability to access sufficient capital at reasonable rates to fund expansion projects, especially in periods of prolonged economic decline when the Company may be unable to access capital markets;
- the availability of skilled labor, equipment, and materials to complete expansion projects;
- adverse weather conditions;
- potential changes in federal, state and local statutes, regulations, and orders, including environmental requirements that delay or prevent a project from proceeding or increase the anticipated cost of the project;
- impediments on the Company's ability to acquire rights-of-way or land rights or to commence and complete construction on a timely basis or on terms that are acceptable to it;
- the Company's ability to construct projects within anticipated costs, including the risk that the Company may incur cost overruns, resulting from inflation or increased costs of equipment, materials, labor, contractor productivity, delays in construction or other factors beyond its control, that the Company may not be able to recover from its customers;
- the lack of future growth in natural gas supply and/or demand; and
- the lack of transportation, storage and throughput commitments.

Any of these risks could prevent a project from proceeding, delay its completion or increase its anticipated costs. There is also the risk that a downturn in the economy and its potential negative impact on natural gas demand may result in either slower development in the Company's expansion projects or adjustments in the contractual commitments supporting such projects. As a result, new facilities could be delayed or may not achieve the Company's expected investment return, which may adversely affect the Company's business, financial condition, results of operations and cash flows.

The inability to continue to access lands owned by third parties could adversely affect the Company's ability to operate and/or expand its pipeline and gathering and processing businesses.

The ability of the Company to operate in certain geographic areas will depend on their success in maintaining existing rights-of-way and obtaining new rights-of-way. Securing additional rights-of-way is also critical to the Company's ability to pursue expansion projects. Even though the Company generally has the right of eminent domain, the Company cannot assure that it will be able to acquire all of the necessary new rights-of-way or maintain access to existing rights-of-way upon the expiration of the current rights-of-way or that all of the rights-of-way will be obtainable in a timely fashion. The Company's financial position could be adversely affected if the costs of new or extended rights-of-way materially increase or the Company is unable to obtain or extend the rights-of-way timely.

Our interstate pipelines are subject to laws, regulations and policies governing the rates they are allowed to charge for their services, which may prevent us from fully recovering our costs.

Laws, regulations and policies governing interstate natural gas pipeline rates could affect the ability of our interstate pipelines to establish rates, to charge rates that would cover future increases in its costs, or to continue to collect rates that cover current costs.

We are required to file tariff rates (also known as recourse rates) with the FERC that shippers may pay for interstate natural gas transportation services. We may also agree to discount these rates on a not unduly discriminatory basis or negotiate rates with shippers who elect not to pay the recourse rates. The FERC must approve or accept all rate filings for us to be allowed to charge such rates.

The FERC may review existing tariffs rates on its own initiative or upon receipt of a complaint filed by a third party. The FERC may, on a prospective basis, order refunds of amounts collected if it finds the rates to have been shown not to be just and reasonable or to have been unduly discriminatory. The FERC has recently exercised this authority with respect to several other pipeline companies. If the FERC were to initiate a proceeding against us and find that our rates were not just and reasonable or unduly discriminatory, the maximum rates we are permitted to charge may be reduced and the reduction could have an adverse effect on our revenues and results of operations.

The costs of our interstate pipeline operations may increase and we may not be able to recover all of those costs due to FERC regulation of our rates. If we propose to change our tariff rates, our proposed rates may be challenged by the FERC or third parties, and the FERC may deny, modify or limit our proposed changes if we are unable to persuade the FERC that changes would result in just and reasonable rates that are not unduly discriminatory. We also may be limited by the terms of rate case settlement agreements or negotiated rate agreements with individual customers from seeking future rate increases, or we may be constrained by competitive factors from charging our tariff rates.

To the extent our costs increase in an amount greater than our revenues increase, or there is a lag between our cost increases and our ability to file for, and obtain rate increases, our operating results would be negatively affected. Even if a rate increase is permitted by the FERC to become effective, the rate increase may not be adequate. We cannot guarantee that our interstate pipelines will be able to recover all of our costs through existing or future rates.

The ability of interstate pipelines held in tax-pass-through entities, like us, to include an allowance for income taxes as a cost-of-service element in their regulated rates has been subject to extensive litigation before the FERC and the courts for a number of years. It is currently the FERC's policy to permit pipelines to include in cost-of-service a tax allowance to reflect actual or potential income tax liability on their public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Under the FERC's policy, we thus remain eligible to include an income tax allowance in the tariff rates we charge for interstate natural gas transportation. The effectiveness of the FERC's policy and the application of that policy remain subject to future challenges, refinement or change by the FERC or the courts.

Our interstate pipelines are subject to laws, regulations and policies governing terms and conditions of service, which could adversely affect our business and results of operations.

In addition to rate oversight, the FERC's regulatory authority extends to many other aspects of the business and operations of our interstate pipelines, including:

- terms and conditions of service;
- the types of services interstate pipelines may or must offer their customers;
- construction of new facilities;

- acquisition, extension or abandonment of services or facilities;
- reporting and information posting requirements;
- accounts and records; and
- relationships with affiliated companies involved in all aspects of the natural gas and energy businesses.

Compliance with these requirements can be costly and burdensome. In addition, we cannot guarantee that the FERC will authorize tariff changes and other activities we might propose to do so in a timely manner and free from potentially burdensome conditions. Future changes to laws, regulations, policies and interpretations thereof in these and other applicable areas may impair our access to capital markets or may impair the ability of our interstate pipelines to compete for business, may impair their ability to recover costs or may increase the cost and burden of operation.

We may incur significant costs and liabilities resulting from performance of pipeline integrity programs and related repairs.

Pursuant to authority under the Natural Gas Pipeline Safety Act ("NGPSA") and Hazardous Liquid Pipeline Safety Act ("HLPSA"), as amended by the Pipeline Safety Improvement Act, the PIPES Act and the 2011 Pipeline Safety Act, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") has established a series of rules requiring pipeline operators to develop and implement integrity management programs for gas transmission and hazardous liquid pipelines that, in the event of a pipeline leak or rupture could affect "high consequence areas," which are areas where a release could have the most significant adverse consequences, including high population areas, certain drinking water sources, and unusually sensitive ecological areas. These regulations require operators of covered pipelines to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

In addition, states have adopted regulations similar to existing PHMSA regulations for intrastate gathering and transmission lines. At this time, we cannot predict the ultimate cost of compliance with applicable pipeline integrity management regulations, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines. Any changes to pipeline safety laws by Congress and regulations by PHMSA that result in more stringent or costly safety standards could have a significant adverse effect on us and similarly situated midstream operators. For instance, changes to regulations governing the safety of gas transmission pipelines and gathering lines are being considered by PHMSA, including, for example, revising the definitions of "high consequence areas" and "gathering lines" and strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed.

Federal, state and local jurisdictions may challenge the Company's tax return positions.

The positions taken by the Company in its tax return filings require significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is also required in assessing the timing and amounts of deductible and taxable items. Despite management's belief that the Company's tax return positions are fully supportable, certain positions may be challenged successfully by federal, state and local jurisdictions.

The Company is subject to extensive federal, state and local laws and regulations regulating the environmental aspects of its business that may increase its costs of operations, expose it to environmental liabilities and require it to make material unbudgeted expenditures.

The Company is subject to extensive federal, state and local laws and regulations regulating the environmental aspects of its business (including air emissions), which are complex, change from time to time and have tended to become increasingly strict. These laws and regulations have necessitated, and in the future may necessitate, increased capital expenditures and operating costs. In addition, certain environmental laws may result in liability without regard to fault concerning contamination at a broad range of properties, including currently or formerly owned, leased or operated properties and properties where the Company disposed of, or arranged for the disposal of, waste.

The Company is currently monitoring or remediating contamination at several of its facilities and at waste disposal sites pursuant to environmental laws and regulations and indemnification agreements. The Company cannot predict with certainty the sites for which it may be responsible, the amount of resulting cleanup obligations that may be imposed on it or the amount and timing of future expenditures related to environmental remediation because of the difficulty of estimating cleanup costs and the uncertainty of payment by other PRPs.

Costs and obligations also can arise from claims for toxic torts and natural resource damages or from releases of hazardous materials on other properties as a result of ongoing operations or disposal of waste. Compliance with amended, new or more stringently enforced existing environmental requirements, or the future discovery of contamination, may require material unbudgeted expenditures. These costs or expenditures could have a material adverse effect on the Company's business, financial condition, results of operations or cash flows, particularly if such costs or expenditures are not fully recoverable from insurance or through the rates charged to customers or if they exceed any amounts that have been reserved.

An impairment of goodwill and intangible assets could reduce our earnings.

As of December 31, 2014, our consolidated balance sheet reflected $1.15 billion of goodwill. Goodwill is recorded when the purchase price of a business exceeds the fair value of the tangible and separately measurable intangible net assets. Accounting principles generally accepted in the United States require us to test goodwill for impairment on an annual basis or when events or circumstances occur, indicating that goodwill might be impaired. Long-lived assets such as intangible assets with finite useful lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If we determine that any of our goodwill or intangible assets were impaired, we would be required to take an immediate charge to earnings with a correlative effect on partners' capital and balance sheet leverage as measured by debt to total capitalization.

The Company's business could be affected adversely by union disputes and strikes or work stoppages by its unionized employees.

As of January 30, 2015, approximately 211 of the Company's 562 employees were represented by collective bargaining units under collective bargaining agreements. Any future work stoppage could, depending on the affected operations and the length of the work stoppage, have a material adverse effect on the Company's business, financial position, results of operations or cash flows.

The adoption of climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the services we provide.

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has adopted rules under the Clean Air Act that, among other things, establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit reviews for certain large stationary sources, which reviews could require securing PSD permits at covered facilities emitting greenhouse gases and meeting "best available control technology" standards for those greenhouse gas emissions. In addition, the EPA has adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified onshore and offshore production facilities and onshore processing, transmission and storage facilities in the United States on an annual basis, which include certain of our operations. While Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases, there has not been significant activity in the form of adopted legislation. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing greenhouse gas emissions by means of cap and trade programs. The adoption of any legislation or regulations that requires reporting of greenhouse gases or otherwise restricts emissions of greenhouse gases from our equipment and operations could require us to incur significant added costs to reduce emissions of greenhouse gases or could adversely affect demand for the natural gas and NGLs we gather and process or fractionate. Moreover, if Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products, which could adversely affect the services we provide.

More stringent regulatory initiatives in the U.S. Gulf of Mexico in the aftermath of the Macondo well oil spill may result in increased costs and delays in offshore oil and natural gas exploration and production operations, which costs and delays could significantly decrease the volume of our business and have a material adverse effect on our results of operations, financial position and liquidity.

In response to an April 2010 fire and explosion aboard the Deepwater Horizon drilling rig and resulting oil spill from the Macondo well operated by a third party in ultra-deep water in the U.S. Gulf of Mexico, federal authorities have pursued a series of regulatory initiatives to address the direct impact of that incident and to prevent similar incidents in the future. Beginning in 2010 and continuing through 2013, the federal government, acting through the U.S. Department of the Interior, or DOI, and its implementing agencies that have since evolved into the present day Bureau of Ocean Energy Management and Bureau of Safety and Environmental Enforcement has issued various rules, Notices to Lessees and Operators and temporary drilling moratoria that impose or result in added environmental and safety measures upon exploration, development and production operators in the U.S. Gulf of Mexico. These regulatory initiatives may serve to effectively slow down the pace of drilling and production operations in the U.S. Gulf of Mexico due to adjustments in operating procedures and certification practices, increased lead times to obtain exploration and production plan reviews, develop drilling applications, and apply for and receive new well permits and thus result in increased costs for affected operators, some of whom are our customers. The increased regulations and cost of drilling operations could result in decreased drilling activity in the areas serviced by us. Furthermore, business decisions by operators not to drill in the areas serviced by us in the future owing to the more rigorous regulatory environmental or increased costs of operating also could result in a reduction in the future development and production of natural gas reserves in the vicinity of our facilities, which could adversely affect our business, financial condition results of operations and cash flows. Also, if similar events were to occur in the future in the U.S. Gulf of Mexico in areas where we conducts operations, the United States could elect to again issue directives to temporarily cease drilling activities and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and gas exploration and development, which developments could have a material adverse effect on our volume of business as well as our financial position, results of operations and liquidity.

The costs of providing postretirement health care benefits and related funding requirements are subject to changes in other postretirement fund values and fluctuating actuarial assumptions and may have a material adverse effect on the Company's financial results. In addition, the passage of the Health Care Reform Act in 2010 could significantly increase the cost of providing health care benefits for Company employees.

The Company provides postretirement healthcare benefits to certain of its employees. The costs of providing postretirement health care benefits and related funding requirements are subject to changes in postretirement fund values and fluctuating actuarial assumptions that may have a material adverse effect on the Company's future financial results. In addition, the passage of the Health Care Reform Act of 2010 could significantly increase the cost of health care benefits for its employees. While certain of the costs incurred in providing such postretirement healthcare benefits are recovered through the rates charged by the Company's regulated businesses, the Company may not recover all of its costs and those rates are generally not immediately responsive to current market conditions or funding requirements. Additionally, if the current cost recovery mechanisms are changed or eliminated, the impact of these benefits on operating results could significantly increase.

The Company's business is highly regulated.

The Company's transportation and storage business is subject to regulation by federal, state and local regulatory authorities. FERC, the U.S. Department of Transportation and various state and local regulatory agencies regulate the interstate pipeline business. In particular, FERC has authority to regulate rates charged by the Company for the transportation and storage of natural gas in interstate commerce. FERC also has authority over the construction, acquisition, operation and disposition of these pipeline and storage assets.

The Company's rates and operations are subject to extensive regulation by federal regulators as well as the actions of Congress and state legislatures and, in some respects, state regulators. The Company cannot predict or control what effect future actions of regulatory agencies may have on its business or its access to the capital markets. Furthermore, the nature and degree of regulation of natural gas companies has changed significantly during the past several decades and there is no assurance that further substantial changes will not occur or that existing policies and rules will not be applied in a new or different manner. Should new and more stringent regulatory requirements be imposed, the Company's business could be unfavorably impacted and the Company could be subject to additional costs that could adversely affect its financial condition or results of operations if these costs are not ultimately recovered through rates.

The Company's transportation and storage business is also influenced by fluctuations in costs, including operating costs such as insurance, postretirement and other benefit costs, wages, outside contractor services costs, asset retirement obligations for certain assets and other operating costs. The profitability of regulated operations depends on the business' ability to collect such increased costs as a part of the rates charged to its customers. To the extent that such operating costs increase in an amount greater than that for which revenue is received, or for which rate recovery is allowed, this differential could impact operating results. The lag between an increase in costs and the ability of the Company to file to obtain rate relief from FERC to recover those increased costs can have a direct negative impact on operating results. As with any request for an increase in rates in a regulatory filing, once granted, the rate increase may not be adequate. In addition, FERC may prevent the business from passing along certain costs in the form of higher rates. Competition may prevent the recovery of increased costs even if allowed in rates.

FERC may also exercise its Section 5 authority to initiate proceedings to review rates that it believes may not be just and reasonable. FERC has recently exercised this authority with respect to several other pipeline companies, as it had in 2007 with respect to Southwest Gas. If FERC were to initiate a Section 5 proceeding against the Company and find that the Company's rates at that time were not just and reasonable due to a lower rate base, reduced or disallowed operating costs, or other factors, the applicable maximum rates the Company is allowed to charge customers could be reduced and the reduction could potentially have a material adverse effect on the Company's business, financial condition, results of operations or cash flows.

A rate reduction is also a possible outcome with any Section 4 rate case proceeding for the regulated entities of the Company, including any rate case proceeding required to be filed as a result of a prior rate case settlement. A regulated entity's rate base, upon which a rate of return is allowed in the derivation of maximum rates, is primarily determined by a combination of accumulated capital investments, accumulated regulatory basis depreciation, and accumulated deferred income taxes. Such rate base can decline due to capital investments being less than depreciation over a period of time, or due to accelerated tax depreciation in excess of regulatory basis depreciation.

The pipeline business of the Company is subject to competition.

The interstate pipeline and storage business of the Company competes with those of other interstate and intrastate pipeline companies in the transportation and storage of natural gas. The principal elements of competition among pipelines are rates, terms of service and the flexibility and reliability of service. Natural gas competes with other forms of energy available to the Company's customers and end-users, including electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability or price of natural gas and other forms of energy, the level of business activity, conservation, legislation and governmental regulations, the capability to convert to alternate fuels and other factors, including weather and natural gas storage levels, affect the demand for natural gas in the areas served by the Company.

Substantial risks are involved in operating a natural gas pipeline system.

Numerous operational risks are associated with the operation of a complex pipeline system. These include adverse weather conditions, accidents, the breakdown or failure of equipment or processes, the performance of pipeline facilities below expected levels of capacity and efficiency, the collision of equipment with pipeline facilities (such as may occur if a third party were to perform excavation or construction work near the facilities) and other catastrophic events beyond the Company's control. In particular, the Company's pipeline system, especially those portions that are located offshore, may be subject to adverse weather conditions, including hurricanes, earthquakes, tornadoes, extreme temperatures and other natural phenomena, making it more difficult for the Company to realize the historic rates of return associated with these assets and operations. A casualty occurrence might result in injury or loss of life, extensive property damage or environmental damage. Insurance proceeds may not be adequate to cover all liabilities or expenses incurred or revenues lost.

Fluctuations in energy commodity prices could adversely affect the business of the Company.

If natural gas prices in the supply basins connected to the pipeline systems of the Company are higher than prices in other natural gas producing regions able to serve the Company's customers, the volume of natural gas transported by the Company may be negatively impacted. Natural gas prices can also affect customer demand for the various services provided by the Company.

The pipeline business of the Company is dependent on a small number of customers for a significant percentage of its sales.

Historically, a small number of customers has accounted for a large portion of the Company's revenue. The loss of any one or more of these customers could have a material adverse effect on the Company's business, financial condition, results of operations or cash flows.

The success of the Company depends on the continued development of additional natural gas reserves in the vicinity of its facilities and its ability to access additional reserves to offset the natural decline from existing sources connected to its system.

The amount of revenue generated by the Company ultimately depends upon its access to reserves of available natural gas. As the reserves available through the supply basins connected to the Company's system naturally decline, a decrease in development or production activity could cause a decrease in the volume of natural gas available for transmission. If production from these natural gas reserves is substantially reduced and not replaced with other sources of natural gas, such as new wells or interconnections with other pipelines, and certain of the Company's assets are consequently not utilized, the Company may have to accelerate the recognition and settlement of asset retirement obligations. Investments by third parties in the development of new natural gas reserves or other sources of natural gas in proximity to the Company's facilities depend on many factors beyond the Company's control. Revenue reductions or the acceleration of asset retirement obligations resulting from the decline of natural gas reserves and the lack of new sources of natural gas may have a material adverse effect on the Company's business, financial condition, results of operations and cash flows.

The pipeline revenues of the Company are generated under contracts that must be renegotiated periodically.

The pipeline revenues of the Company are generated under natural gas transportation contracts that expire periodically and must be replaced. Although the Company will actively pursue the renegotiation, extension and/or replacement of all of its contracts, it cannot assure that it will be able to extend or replace these contracts when they expire or that the terms of any renegotiated contracts will be as favorable as the existing contracts. If the Company is unable to renew, extend or replace these contracts, or if the Company renews them on less favorable terms, it may suffer a material reduction in revenues and earnings.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Exchange Act. Forward-looking statements are based on management's beliefs and assumptions. These forward-looking statements, which address the Company's expected business and financial performance, among other matters, are identified by terms and phrases such as: anticipate, believe, intend, estimate, expect, continue, should, could, may, plan, project, predict, will, potential, forecast and similar expressions. Forward-looking statements involve risks and uncertainties that may or could cause actual results to be materially different from the results predicted. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- changes in demand for natural gas and related services by customers, in the composition of the Company's customer base and in the sources of natural gas accessible to the Company's system;
- the effects of inflation and the timing and extent of changes in the prices and overall demand for and availability of natural gas as well as electricity, oil, coal and other bulk materials and chemicals;
- adverse weather conditions, such as warmer or colder than normal weather in the Company's service territories, as applicable, and the operational impact of natural disasters;
- changes in laws or regulations, third-party relations and approvals, and decisions of courts, regulators and/or governmental bodies affecting or involving the Company, including deregulation initiatives and the impact of rate and tariff proceedings before FERC and various state regulatory commissions;
- the speed and degree to which additional competition, including competition from alternative forms of energy, is introduced to the Company's business and the resulting effect on revenues;
- the impact and outcome of pending and future litigation and/or regulatory investigations, proceedings or inquiries;
- the ability to comply with or to successfully challenge existing and/or or new environmental, safety and other laws and regulations;
- unanticipated environmental liabilities;
- the uncertainty of estimates, including accruals and costs of environmental remediation;
- the impact of potential impairment charges;
- the ability to acquire new businesses and assets and to integrate those operations into its existing operations, as well as its ability to expand its existing businesses and facilities;
- the timely receipt of required approvals by applicable governmental entities for the construction and operation of the pipelines and other projects;
- the ability to complete expansion projects on time and on budget;
- the ability to control costs successfully and achieve operating efficiencies, including the purchase and implementation of new technologies for achieving such efficiencies;
- the impact of factors affecting operations such as maintenance or repairs, environmental incidents, natural gas pipeline system constraints and relations with labor unions representing bargaining-unit employees;
- the performance of contractual obligations by customers, service providers and contractors;
- exposure to customer concentrations with a significant portion of revenues realized from a relatively small number of customers and any credit risks associated with the financial position of those customers;
- changes in the ratings of the Company's debt securities;
- the risk of a prolonged slow-down in growth or decline in the United States economy or the risk of delay in growth or decline in the United States economy, including liquidity risks in United States credit markets;
- the impact of unsold pipeline capacity being greater than expected;
- changes in interest rates and other general market and economic conditions, and in the Company's ability to obtain additional financing on acceptable terms, whether in the capital markets or otherwise;

- declines in the market prices of equity and debt securities and resulting funding requirements for other postretirement benefit plans;
- acts of nature, sabotage, terrorism or other similar acts that cause damage to the facilities or those of the Company's suppliers' or customers' facilities;
- market risks beyond the Company's control affecting its risk management activities including market liquidity, commodity price volatility and counterparty creditworthiness;
- the availability/cost of insurance coverage and the ability to collect under existing insurance policies;
- the risk that material weaknesses or significant deficiencies in internal controls over financial reporting could emerge or that minor problems could become significant;
- changes in accounting rules, regulations and pronouncements that impact the measurement of the results of operations, the timing of when such measurements are to be made and recorded and the disclosures surrounding these activities;
- the effects of changes in governmental policies and regulatory actions, including changes with respect to income and other taxes, environmental compliance, climate change initiatives, authorized rates of recovery of costs (including pipeline relocation costs), and permitting for new natural gas production accessible to the Company's systems;
- market risks affecting the Company's pricing of its services provided and renewal of significant customer contracts;
- actions taken to protect species under the Endangered Species Act and the effect of those actions on the Company's operations;
- the impact of union disputes, employee strikes or work stoppages and other labor-related disruptions; and
- other risks and unforeseen events, including other financial, operational and legal risks and uncertainties detailed from time to time in filings with the SEC.

These factors are not necessarily all of the important factors that could cause actual results to differ materially from those expressed in any of the Company's forward-looking statements. Other factors could also have material adverse effects on the Company's future results. In light of these risks, uncertainties and assumptions, the events described in forward-looking statements might not occur or might occur to a different extent or at a different time than the Company has described. The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by law.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

See "Item 1. Business" for information concerning the general location and characteristics of the important physical properties and assets of the Company.

ITEM 3. LEGAL PROCEEDINGS

The Company and certain of its affiliates are occasionally parties to lawsuits and administrative proceedings incidental to their businesses involving, for example, claims for personal injury and property damage, contractual matters, various tax matters, and rates and licensing. The Company and its affiliates are also subject to various federal, state and local laws and regulations relating to the environment, as described in "Item 1. Business – Regulation." Several of these companies have been named parties to various actions involving environmental issues. Based on the Company's current knowledge and subject to future legal and factual developments, the Company's management believes that it is unlikely that these actions, individually or in the aggregate, will have a material adverse effect on its consolidated financial position, results of operations or cash flows. For additional information regarding various pending administrative and judicial proceedings involving regulatory, environmental and other legal matters, reference is made to Note 14 to our consolidated financial statements. Also see "Item 1A. Risk Factors."

On or around December 24, 2014, PHMSA issued to PEPL a Notice of Proposed Safety Order (the "Notice") regarding the PEPL pipeline system. The Notice stated that PHMSA had initiated an investigation of the safety of the PEPL pipeline system and specifically referenced two incidents: 1) a November 28, 2013, incident on PEPL's 400 line approximately 4.7 miles downstream of the Houstonia compressor station near Hughesville, Missouri, and 2) an October 13, 2014, failure on the PEPL 100 line near Centerview, Missouri. The Notice further mentioned other incidents on the PEPL pipeline system that PHMSA claims to have addressed with PEPL. The Notice also stated that "[a]s a result of [PHMSA's] investigation, it appears that conditions exist on the

PEPL pipeline system that pose a pipeline integrity risk to public safety, property or the environment.” PEPL is fully cooperating with PHMSA and its investigation.

ITEM 4. MINE SAFETY DISCLOSURE

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON UNITS, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Southern Union Panhandle LLC, an indirect wholly-owned subsidiary of ETP, serves as the general partner of PEPL and owns a 1% general partnership interest in PEPL. ETP also indirectly owns a 99% limited partnership interest in PEPL. See Note 1 to our consolidated financial statements.

ITEM 6. SELECTED FINANCIAL DATA

Item 6, Selected Financial Data, has been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

(Tabular dollar amounts are in millions)

Introduction

The information in Item 7 has been prepared pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K. Accordingly, this Item 7 includes only management’s narrative analysis of the results of operations and certain supplemental information.

References to “we,” “us,” “our”, the “Company” and “Panhandle” shall mean Panhandle Eastern Pipe Line Company, LP and its subsidiaries.

Our former consolidated subsidiary, Trunkline LNG Company, LLC, changed its name in September 2014 to Lake Charles LNG Company, LLC. All references to this company throughout this document reflect the new name of the company, regardless of whether the disclosure relates to periods or events prior to the dates of the name change.

Overview

The Company’s business purpose is to provide interstate transportation and storage of natural gas in a safe, efficient and dependable manner. The Company operates approximately 10,000 miles of interstate pipelines that transport up to 6.8 Bcf/d of natural gas. Demand for natural gas transmission services on the Company’s pipeline system is seasonal, with the highest throughput and a higher portion of annual total operating revenues occurring in the traditional winter heating season, which occurs during the first and fourth calendar quarters. For additional information related to the Company’s line of business, locations of operations and services provided, see “Item 1. Business.”

The Company’s business is conducted through both short- and long-term contracts with customers. Shorter-term contracts, both firm and interruptible, tend to have a greater impact on the volatility of revenues. Short-term and long-term contracts are affected by changes in market conditions and competition with other pipelines, changing supply sources and volatility in natural gas prices and basis differentials. Since the majority of the Company’s revenues are related to firm capacity reservation charges, which customers pay whether they utilize their contracted capacity or not, volumes transported do not have as significant an impact on revenues over the short-term. However, longer-term demand for capacity may be affected by changes in the customers’ actual and anticipated utilization of their contracted capacity and other factors. For additional information concerning the Company’s related risk factors and the weighted average remaining lives of firm transportation and storage contracts, see “Item 1A. Risk Factors” and “Item 1. Business,” respectively.

The Company’s regulated transportation and storage businesses can file (or be required to file) for changes in their rates, which are subject to approval by FERC. Although a significant portion of the Company’s contracts are discounted or negotiated rate contracts, changes in rates and other tariff provisions resulting from regulatory proceedings have the potential to impact negatively the Company’s results of operations and financial condition. For information related to the status of current rate filings, see “Item 1. Business – Regulation.”

Results of Operations

On January 10, 2014, the Company consummated a merger with Southern Union, the indirect parent of the Company, and PEPL Holdings, the sole limited partner of the Company, pursuant to which each of Southern Union and PEPL Holdings, a wholly-owned subsidiary of Southern Union, were merged with and into the Company (the "Panhandle Merger"), with the Company surviving the Panhandle Merger. We have accounted for this transaction as a reorganization of entities under common control; therefore, the consolidated financial statements of the Company were retrospectively adjusted to consolidate Southern Union for all periods.

The following table illustrates the results of operations of the Company:

	Year Ended December 31, 2014	Year Ended December 31, 2013
OPERATING REVENUES:		
Transportation and storage of natural gas	$ 555	$ 576
LNG terminalling	—	216
Other	26	293
Total operating revenues [1]	581	1,085
OPERATING EXPENSES:		
Cost of natural gas and other energy	3	228
Operating, maintenance and general	255	361
Depreciation and amortization	130	189
Goodwill impairment	—	689
Total operating expenses	388	1,467
OPERATING INCOME (LOSS)	193	(382)
OTHER INCOME (EXPENSE):		
Interest expense, net of interest capitalized	(66)	(111)
Equity in earnings (losses) of unconsolidated affiliates	(12)	15
Interest income — affiliates	23	9
Other, net	5	(3)
Total other expenses, net	(50)	(90)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	143	(472)
Income tax expense from continuing operations	146	98
LOSS FROM CONTINUING OPERATIONS	(3)	(570)
Income from discontinued operations	—	35
NET LOSS	(3)	(535)
LESS: NET INCOME (LOSS) ATTRIBUTABLE TO NONCONTROLLING INTEREST	6	(36)
NET LOSS ATTRIBUTABLE TO PARTNERS	$ (9)	$ (499)
Panhandle natural gas volumes transported (TBtu): [2]		
PEPL	625	613
Trunkline	694	722
Sea Robin	130	141

(1) Reservation revenues comprised 83% and 88% of total operating revenues for the years ended December 31, 2014 and 2013, respectively.

(2) Includes transportation deliveries made throughout the Company's pipeline network.

The following is a discussion of the significant items and variances impacting the Company's net income during the periods presented above:

- *Operating Revenues.* Operating revenues decreased for the year ended December 31, 2014 compared to the prior year primarily due to the deconsolidation of Lake Charles LNG in 2014 and SUGS in 2013. In addition, the decrease in operating revenues reflected the recognition in 2013 of $52 million received in connection with the buyout of a customer contract. These decreases were partially offset by an increase of approximately $29 million due to capacity sold at higher rates and loan related activity from higher basis differentials and spot prices on the Panhandle pipeline, primarily driven by favorable impacts from the cold winter season during the first quarter of 2014.

- *Operating Expenses.* Operating expenses decreased for the year ended December 31, 2014 compared to the prior year primarily due to the deconsolidation of SUGS and Lake Charles LNG. Operating expenses included in the year ended December 31, 2013 related to SUGS and Lake Charles LNG were $56 million and $30 million, respectively. In addition, during the year ended December 31, 2013 the Company recorded a $689 million goodwill impairment related to Lake Charles LNG. The remainder of the decrease in operating, maintenance and general was primarily attributable to reduced general and administrative costs related to professional fees of $19 million.

- *Interest Expense, Net of Interest Capitalized.* Interest expense decreased for the year ended December 31, 2014 compared to the prior year due to repayment of long-term debt during 2013.

- *Equity in Earnings (Losses) of Unconsolidated Affiliates*. Equity in earnings (losses) of unconsolidated affiliates decreased primarily due to a goodwill impairment recorded by Regency. As a result, the Company recognized a non-cash loss based on its proportionate ownership in Regency.

- *Interest Income - Affiliates.* Interest income from affiliates increased for the year ended December 31, 2014 compared to the prior year due to a note receivable from ETP that was entered into during the third quarter 2013.

- *Income Taxes.* The increase in the effective tax rate for the year ended December 31, 2014 was primarily due to the Lake Charles LNG Transaction, which was treated as a sale for tax purposes, resulting in $70 million of incremental income tax expense. For the year ended December 31, 2013, the effective tax rate also reflected a $241 million tax impact as a result of a $689 million non-deductible goodwill impairment.

- *Income From Discontinued Operations.* Income from discontinued operations for the year ended December 31, 2013 reflected the results of operations of MGE and NEG, both of which were sold in 2013.

OTHER MATTERS

Environmental Matters

The Company is subject to federal, state and local laws and regulations relating to the protection of the environment. These evolving laws and regulations may require expenditures over a long period of time to control environmental impacts. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures. These procedures are designed to achieve compliance with such laws and regulations. For additional information concerning the impact of environmental regulation on the Company, see Note 14 to our consolidated financial statements.

Contractual Obligations

The following table summarizes the Company's expected contractual obligations by payment due date as of December 31, 2014:

	Contractual Obligations						
	Total	2015	2016	2017	2018	2019	2020 and thereafter
Operating leases [1]	$ 16	$ 2	$ 2	$ 3	$ 3	$ 2	$ 4
Total long-term debt [2] [3]	1,091	—	—	300	400	150	241
Interest payments on debt [4]	463	75	75	75	42	22	174
Natural gas purchases [5]	72	4	4	4	4	4	52
Firm capacity payments [6]	89	26	22	21	16	4	—
OPEB funding [7]	48	8	8	8	8	8	8
Total [8]	$ 1,779	$ 115	$ 111	$ 411	$ 473	$ 190	$ 479

(1) Lease of various assets utilized for operations.

(2) The Company is party to debt agreements containing certain covenants that, if not satisfied, would give rise to an event of default that would cause such debt to become immediately due and payable. Such covenants require the Company to maintain a fixed charge coverage ratio, a leverage ratio and to meet certain ratios of earnings before depreciation, interest and taxes to cash interest expense. At December 31, 2014, the Company was in compliance with all of its covenants. See Note 7 to our consolidated financial statements.

(3) The long-term debt cash obligations exclude $99 million of unamortized fair value adjustments as of December 31, 2014.

(4) Interest payments on debt are based upon the applicable stated or variable interest rates as of December 31, 2014.

(5) The Company has tariffs in effect for its utility service areas that provide for recovery of its purchased natural gas costs under defined methodologies.

(6) Charges for third party storage capacity.

(7) Panhandle is committed to the funding levels of $8 million per year until modified by future rate proceedings, the timing of which is uncertain.

(8) Excludes non-current deferred tax liability of $1.51 billion due to uncertainty of the timing of future cash flows for such liabilities.

Contingencies

See Note 14 to our consolidated financial statements.

Inflation

The Company believes that inflation has caused, and may continue to cause, increases in certain operating expenses, and will continue to require higher capital replacement and construction costs. The Company continually reviews the adequacy of its rates in relation to such increasing cost of providing services, the inherent regulatory lag in adjusting its tariff rates and the rates it is actually able to charge in its markets.

Regulatory

See Note 14 to our consolidated financial statements.

Rate Matters

Sea Robin Rate Case. On December 2, 2013, Sea Robin filed a general NGA Section 4 rate case at the FERC as required by a previous rate case settlement. In the filing, Sea Robin seeks to increase its authorized rates to recover costs related to asset retirement obligations, depreciation, and return and taxes. A settlement was reached with the shippers and a stipulation and agreement was filed with the FERC on July 23, 2014. The settlement was certified to the FERC by the administrative law judge on October 7, 2014 and was conditionally approved by the FERC on December 18, 2014.

New Accounting Standards

In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers (Topic 606)* (“ASU 2014-09”), which clarifies the principles for recognizing revenue based on the core principle that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period, with earlier adoption not permitted. ASU 2014-09 can be adopted either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment as of the date of adoption. The Partnership is currently evaluating the impact, if any, that adopting this new accounting standard will have on our revenue recognition policies.

In April 2014, the FASB issued Accounting Standards Update No. 2014-08, *Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity* (“ASU 2014-08”), which changed the requirements for reporting discontinued operations. Under ASU 2014-08, a disposal of a component of an entity or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has or will have a major effect on an entity’s operations and financial results. ASU 2014-08 is effective for all disposals or classifications as held for sale of components of an entity that occur within fiscal years beginning after December 15, 2014, and early adoption is permitted. We expect to adopt this standard for the year ending December 31, 2015. ASU 2014-08 could have an impact on whether transactions will be reported in discontinued operations in the future, as well as the disclosures required when a component of an entity is disposed.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Interest Rate Risk

At December 31, 2014, the interest rate on 95% of the Company's long-term debt was fixed with no outstanding interest rate swaps.

The Company previously had fixed-rate interest rate swaps, all of which were settled in 2013 and 2014. The Company has no outstanding interest rate swap agreements as of December 31, 2014.

See Note 7 and Note 10 to our consolidated financial statements.

Commodity Price Risk

The Company is exposed to some commodity price risk with respect to natural gas used in operations by its interstate pipelines. Specifically, the pipelines receive natural gas from customers for use in generating compression to move the customers' natural gas. Additionally the pipelines may have to settle system imbalances when customers' actual receipts and deliveries do not match. When the amount of natural gas utilized in operations by the pipelines differs from the amount provided by customers, the pipelines may use natural gas from inventory or may have to buy or sell natural gas to cover these or other operational needs, resulting in commodity price risk exposure to the Company. In addition, there is other indirect exposure to the extent commodity price changes affect customer demand for and utilization of transportation and storage services provided by the Company. At December 31, 2014, there were no hedges in place with respect to natural gas price risk associated with the Company's interstate pipeline operations.

Credit Risk

Credit risk refers to the risk that a shipper may default on its contractual obligations resulting in a credit loss to the Company. A credit policy has been approved and implemented to govern the Company's portfolio of shippers with the objective of mitigating credit losses. This policy establishes guidelines, controls, and limits, consistent with FERC filed tariffs, to manage credit risk within approved tolerances by mandating an appropriate evaluation of the financial condition of existing and potential shippers, monitoring agency credit ratings, and by implementing credit practices that limit credit exposure according to the risk profiles of the shippers. Furthermore, the Company may, at times, require collateral under certain circumstances in order to mitigate credit risk as necessary.

The Company's shippers consist of a diverse portfolio of customers across the energy industry, including oil and gas producers, midstream companies, municipalities, utilities, and commercial and industrial end users. Our overall exposure may be affected positively or negatively by macroeconomic or regulatory changes that could impact our shippers to one extent or another. Currently, management does not anticipate a material adverse effect in our financial position or results of operations as a consequence of shipper non-performance.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The financial statements starting on page F-1 of this report are incorporated by reference.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

An evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rules 13a–15(e) and 15d–15(e) of the Exchange Act) as of the end of the period covered by this report. Based upon that evaluation, management, including the Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were adequate and effective as of December 31, 2014.

Management's Report on Internal Control over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in the 2013 *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO framework").

Based on our evaluation under the COSO framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2014.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Item 10, Directors, Executive Officers and Corporate Governance, has been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

Item 11, Executive Compensation, has been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Item 12, Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, has been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Item 13, Certain Relationships and Related Transactions, and Director Independence, has been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The following table sets forth fees billed by Grant Thornton LLP for the audits of our annual financial statements and other services rendered:

	Years Ended December 31,	
	2014	2013
Audit fees (1)	$ 800,000	$ 1,314,250
Audit related fees (2)	27,500	547,300
Total Fees	$ 827,500	$ 1,861,550

(1) Includes fees for audits of annual financial statements of our companies, reviews of the related quarterly financial statements, and services that are normally provided by the independent accountants in connection with statutory and regulatory filings or engagements, including reviews of documents filed with the SEC and services related to the audit of our internal controls over financial reporting.

(2) Includes fees in 2013 for financial statement audits of subsidiary entities in connection with the contribution of SUGS from Southern Union to Regency and the sale of Southern Union's distribution operations. Includes fees in 2014 and 2013 in connection with the services organization control report on PEPL's centralized data center.

The ETP Audit Committee is responsible for the oversight of our accounting, reporting and financial practices, pursuant to the charter of the ETP Audit Committee. The ETP Audit Committee has the responsibility to select, appoint, engage, oversee, retain, evaluate and terminate our external auditors; pre-approve all audit and non-audit services to be provided, consistent with all applicable laws, to us by our external auditors; and establish the fees and other compensation to be paid to our external auditors. The ETP Audit Committee also oversees and directs our internal auditing program and reviews our internal controls.

The ETP Audit Committee has adopted a policy for the pre-approval of audit and permitted non-audit services provided by our principal independent accountants. The policy requires that all services provided by Grant Thornton LLP including audit services, audit-related services, tax services and other services, must be pre-approved by the ETP Audit Committee.

The ETP Audit Committee reviews the external auditors' proposed scope and approach as well as the performance of the external auditors. It also has direct responsibility for and sole authority to resolve any disagreements between our management and our external auditors regarding financial reporting, regularly reviews with the external auditors any problems or difficulties the auditors encountered in the course of their audit work, and, at least annually, uses its reasonable efforts to obtain and review a report from the external auditors addressing the following (among other items):

- the auditors' internal quality-control procedures;
- any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors;
- the independence of the external auditors;
- the aggregate fees billed by our external auditors for each of the previous two years; and
- the rotation of the lead partner.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this Report:

(1) Financial Statements - see Index to Financial Statements appearing on page F-1.

(2) Financial Statement Schedules - None.

(3) Exhibits - see Index to Exhibits set forth on page E-1.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, Panhandle Eastern Pipe Line Company, LP has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PANHANDLE EASTERN PIPE LINE COMPANY, LP

Date: February 26, 2015

By: /s/ Martin Salinas, Jr.
Martin Salinas, Jr.
Chief Financial Officer (duly authorized to sign on behalf of the registrant)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Panhandle Pipe Line Company, LP, in the capacities and on the dates indicated:

	Signature	Title	Date
(i)	Principal executive officer: /s/ Kelcy L. Warren Kelcy L. Warren	Chief Executive Officer	February 26, 2015
(ii)	Principal financial officer: /s/ Martin Salinas, Jr. Martin Salinas, Jr.	Chief Financial Officer	February 26, 2015

(iii) The Board of Directors of SUG Holding Company, Sole Member of Southern Union Panhandle, LLC, General Partner of Panhandle Eastern Pipe Line Company, L.P

Signature	Title	Date
/s/ Kelcy L. Warren Kelcy L. Warren	Chief Executive Officer and Director, SUG Holding Company	February 26, 2015
/s/ John W. McReynolds John W. McReynolds	Director, SUG Holding Company	February 26, 2015

INDEX TO EXHIBITS

	Exhibit Number	Description
(*)	3(a)	Certificate of Formation of Panhandle Eastern Pipe Line Company, LP. (Filed as Exhibit 3.A to Panhandle's Form 10-K for the year ended December 31, 2004.)
(*)	3(b)	Limited Partnership Agreement of Panhandle Eastern Pipe Line Company, LP, dated as of June 29, 2004, between Southern Union Company and Southern Union Panhandle LLC. (Filed as Exhibit 3.B to Panhandle's Form 10-K for the year ended December 31, 2004.)
(*)	3(c)	Amendment No. 1, dated January 10, 2014 to Agreement of Limited Partnership of Panhandle Eastern Pipe Line Company, LP (Filed as Exhibit 3.1 to Panhandle's Form 8-K filed on January 10, 2014.)
(*)	4(a)	Indenture dated as of March 29, 1999, among CMS Panhandle Holding Company, Panhandle Eastern Pipe Line Company and NBD Bank (the predecessor to Bank One Trust Company, National Association, J.P. Morgan Trust Company, National Association, The Bank of New York Trust Company, N.A. and The Bank of New York Mellon Trust Company, N.A.), as Trustee. (Filed as Exhibit 4(a) to Panhandle's Form 10-Q for the quarter ended March 31, 1999.)
(*)	4(b)	First Supplemental Indenture dated as of March 29, 1999, among CMS Panhandle Holding Company, Panhandle Eastern Pipe Line Company and NBD Bank (the predecessor to Bank One Trust Company, National Association, J.P. Morgan Trust Company, National Association, The Bank of New York Trust Company, N.A. and The Bank of New York Mellon Trust Company, N.A.), as Trustee, including a form of Guarantee by Panhandle Eastern Pipe Line Company of the obligations of CMS Panhandle Holding Company. (Filed as Exhibit 4(b) to Panhandle's Form 10-Q for the quarter ended March 31, 1999.)
(*)	4(c)	Second Supplemental Indenture dated as of March 27, 2000, between Panhandle and Bank One Trust Company, National Association (succeeded to by The Bank of New York Mellon Trust Company, N.A., which changed its name to The Bank of New York Mellon Trust Company, N.A.), as Trustee. (Filed as Exhibit 4(e) to Panhandle's Form S-4 (File No. 333-39850) filed on June 22, 2000.)
(*)	4(d)	Third Supplemental Indenture dated as of August 18, 2003, between Panhandle and Bank One Trust Company, National Association (succeeded to by The Bank of New York Mellon Trust Company, N.A., which changed its name to The Bank of New York Mellon Trust Company, N.A.), as Trustee. (Filed as Exhibit 4(d) to Panhandle's Form 10-Q for the quarter ended September 30, 2003.)
(*)	4(e)	Fourth Supplemental Indenture dated as of March 12, 2004, between Panhandle and J.P. Morgan Trust Company, National Association (succeeded to by The Bank of New York Mellon Trust Company, N.A., which changed its name to The Bank of New York Mellon Trust Company, N.A.), as Trustee. (Filed as Exhibit 4.E to Panhandle's Form 10-K for the year ended December 31, 2004.)
(*)	4(f)	Fifth Supplemental Indenture dated as of October 26, 2007, between Panhandle and The Bank of New York Trust Company, N.A. (now known as The Bank of New York Mellon Trust Company, N.A.), as Trustee (Filed as Exhibit 4.1 to Panhandle's Form 8-K filed on October 29, 2007.)
(*)	4(g)	Form of Sixth Supplemental Indenture, dated as of June 12, 2008, between Panhandle and The Bank of New York Trust Company, N.A. (now known as The Bank of New York Mellon Trust Company, N.A.), as Trustee (Filed as Exhibit 4.1 to Panhandle's Form 8-K filed on June 11, 2008.)
(*)	10(a)	Credit Agreement between Trunkline LNG Holdings, LLC, as borrower, Panhandle Eastern Pipeline Company, LP and Trunkline LNG Company, LLC, as guarantors, the financial institutions listed therein and the Bank of Tokyo-Mitsubishi UFJ, Ltd., as administrative agent, dated as of February 23, 2012 (Filed as Exhibit 10(a) to Panhandle's Form 10-K for the year ended December 31, 2011.)
(*)	10(b)	Form of Seventh Supplemental Indenture, to be dated as of June 2, 2009, between Panhandle and The Bank of New York Mellon Trust Company, N.A. (Filed as Exhibit 4.1 to Panhandle's Form 8-K filed on May 28, 2009.)
(*)	10(c)	Amended and Restated Credit Agreement between Trunkline LNG Holdings, LLC, as borrower, Panhandle Eastern Pipe Line Company, LP and CrossCountry Citrus, LLC, as guarantors, the financial institutions listed therein and Bayerische Hypo-Und Vereinsbank AG, New York Branch, as administrative agent, dated as of June 29, 2007 (Filed as Exhibit 10.1 to Panhandle's Form 8-K filed on July 6, 2007.)

(*)	10(d)	Amendment Number 1 to the Amended and Restated Credit Agreement between Trunkline LNG Holdings, LLC as borrower, Panhandle Eastern Pipe Line Company, LP and CrossCountry Citrus, LLC, as guarantors, the financial institutions listed therein and Bayerische Hypo-Und Vereinsbank AG, New York Branch, as administrative agent, dated as of June 13, 2008 (Filed as Exhibit 10(b) to Panhandle's Form 10-Q for the quarter ended June 30, 2008.)

	Exhibit Number	Description
(*)	10(e)	Amended and Restated Promissory Note made by CrossCountry Citrus, LLC, as borrower, in favor of Trunkline LNG Holdings LLC, as holder, dated as of June 13, 2008 (Filed as Exhibit 10(d) to Panhandle's Form 10-Q for the quarter ended June 30, 2008.)
(*)	10(f)	Transfer Agreement, dated February 19, 2014, by and between Energy Transfer Partners, L.P. and Panhandle Eastern Pipe Line Company, LP (Filed as Exhibit 10.1 to Panhandle's Form 8-K filed on February 19, 2014.)
	12.1	Computation of Ratio of Earnings to Fixed Charges.
	31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
	31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(**)	32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(**)	32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
	99.1	Audited financial statements of Regency Energy Partners LP as of and for the years ended December 31, 2014, 2013 and 2012.
(*)	99.2	Audited financial statements of Midcontinent Express Pipeline LLC as of and for the years ended December 31, 2014, 2013 and 2012 (incorporated by reference to Exhibit 99.3 of Regency Energy Partners LP Form 10-K for the year ended December 31, 2014, File No. 1-35262.)
	101.INS	XBRL Instance Document
	101.SCH	XBRL Taxonomy Extension Schema Document
	101.CAL	XBRL Taxonomy Calculation Linkbase Document
	101.DEF	XBRL Taxonomy Extension Definitions Document
	101.LAB	XBRL Taxonomy Label Linkbase Document
	101.PRE	XBRL Taxonomy Presentation Linkbase Document

* Indicates exhibit incorporated by reference as indicated; all other exhibits are filed herewith, except as noted otherwise.

** Furnished herewith.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS
Panhandle Eastern Pipe Line Company, LP and Subsidiaries

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Managers
Panhandle Eastern Pipe Line Company, LP

We have audited the accompanying consolidated balance sheets of Panhandle Eastern Pipe Line Company, LP (a Delaware limited partnership) and subsidiaries (the “Partnership”) as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income (loss), partners’ capital, and cash flows for the years ended December 31, 2014 and 2013, the period from March 26, 2012 to December 31, 2012, and the period from January 1, 2012 to March 25, 2012. These financial statements are the responsibility of the Partnership’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. We were not engaged to perform an audit of the Partnership’s 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, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Panhandle Eastern Pipe Line Company, LP and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for the years ended December 31, 2014 and 2013, the period from March 26, 2012 to December 31, 2012, and the period from January 1, 2012 to March 25, 2012 in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Houston, Texas
February 26, 2015

FINANCIAL STATEMENTS

Southern Union's March 26, 2012 merger transaction with ETE was accounted for by ETE using business combination accounting. Under this method, the purchase price paid by the acquirer is allocated to the assets acquired and liabilities assumed as of the acquisition date based on their fair value. By the application of "push-down" accounting, PEPL's assets, liabilities and partners' capital were accordingly adjusted to fair value on March 26, 2012. Determining the fair value of certain assets and liabilities assumed is judgmental in nature and often involves the use of significant estimates and assumptions.

Due to the application of "push-down" accounting, the Company's financial statements and certain footnote disclosures are presented in two distinct periods to indicate the application of two different bases of accounting. Periods prior to March 26, 2012 are identified herein as "Predecessor," while periods subsequent to the ETE Merger are identified as "Successor."

PANHANDLE EASTERN PIPE LINE COMPANY, LP

CONSOLIDATED BALANCE SHEETS

(Dollars in millions)

	December 31,	
	2014	2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 32	$ 17
Accounts receivable, net	58	69
Accounts receivable from related companies	128	64
Exchanges receivable	11	19
Inventories	119	203
Other current assets	13	18
Total current assets	361	390
PROPERTY, PLANT AND EQUIPMENT:		
Plant in service	3,352	4,208
Construction work in progress	43	70
	3,395	4,278
Accumulated depreciation and amortization	(269)	(216)
Net property, plant and equipment	3,126	4,062
INVESTMENTS IN UNCONSOLIDATED AFFILIATES	1,443	1,525
GOODWILL	1,152	1,336
NOTE RECEIVABLE FROM RELATED PARTY	—	396
OTHER NON-CURRENT ASSETS, net	109	147
Total assets	$ 6,191	$ 7,856

The accompanying notes are an integral part of these consolidated financial statements.

PANHANDLE EASTERN PIPE LINE COMPANY, LP

CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	December 31, 2014	December 31, 2013
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$ 1	$ 1
Accounts payable	6	33
Accounts payable to related companies	38	181
Exchanges payable	114	207
Accrued interest	12	12
Price risk management liabilities	—	10
Customer advances and deposits	10	17
Accrued and other current liabilities	56	52
Total current liabilities	237	513
LONG-TERM DEBT, less current maturities	1,189	1,246
NOTE PAYABLE TO RELATED PARTY	—	1,090
NON-CURRENT PRICE RISK MANAGEMENT LIABILITIES	—	15
DEFERRED INCOME TAXES	1,511	1,659
ADVANCES FROM AFFILIATES	51	—
OTHER NON-CURRENT LIABILITIES	278	265
COMMITMENTS AND CONTINGENCIES (Note 14)		
PARTNERS' CAPITAL:		
Partners' capital	2,925	3,551
Accumulated other comprehensive income	—	3
Total partners' capital	2,925	3,554
Noncontrolling interest	—	(486)
Total liabilities and partners' capital	$ 6,191	$ 7,856

The accompanying notes are an integral part of these consolidated financial statements.

PANHANDLE EASTERN PIPE LINE COMPANY, LP

CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in millions)

	Successor			Predecessor
	Year Ended December 31, 2014	Year Ended December 31, 2013	Period from Acquisition (March 26, 2012) to December 31, 2012	Period from January 1, 2012 to March 25, 2012
OPERATING REVENUES:				
Transportation and storage of natural gas	$ 555	$ 576	$ 437	$ 121
LNG terminalling	—	216	166	51
Other	26	293	660	271
Total operating revenues	581	1,085	1,263	443
OPERATING EXPENSES:				
Cost of natural gas and other energy	3	228	521	197
Operating, maintenance and general	255	361	377	116
Depreciation and amortization	130	189	179	49
Goodwill impairment	—	689	—	—
Total operating expenses	388	1,467	1,077	362
OPERATING INCOME (LOSS)	193	(382)	186	81
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(66)	(111)	(131)	(50)
Equity in earnings (losses) of unconsolidated investments	(12)	15	(7)	16
Interest income — affiliates	23	9	—	—
Other, net	5	(3)	2	(2)
Total other expenses, net	(50)	(90)	(136)	(36)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	143	(472)	50	45
Income tax expense from continuing operations	146	98	39	12
INCOME (LOSS) FROM CONTINUING OPERATIONS	(3)	(570)	11	33
Income from discontinued operations	—	35	28	17
NET INCOME (LOSS)	(3)	(535)	39	50
LESS: NET INCOME (LOSS) ATTRIBUTABLE TO NONCONTROLLING INTEREST	6	(36)	(49)	10
NET INCOME (LOSS) ATTRIBUTABLE TO PARTNERS	$ (9)	$ (499)	$ 88	$ 40

The accompanying notes are an integral part of these consolidated financial statements.

PANHANDLE EASTERN PIPE LINE COMPANY, LP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Dollars in millions)

	Successor			Predecessor
	Year Ended December 31, 2014	Year Ended December 31, 2013	Period from Acquisition (March 26, 2012) to December 31, 2012	Period from January 1, 2012 to March 25, 2012
Net income (loss)	$ (3)	$ (535)	$ 39	$ 50
Other comprehensive income (loss), net of tax:				
Change in fair value of interest rate hedges	—	—	—	4
Reclassification of unrealized loss on interest rate hedges into earnings	—	—	—	5
Change in fair value of commodity hedges	—	(3)	(4)	3
Reclassification of unrealized (gain) loss on commodity hedges into earnings	—	6	1	(1)
Actuarial gain (loss) relating to postretirement benefits	(3)	25	(22)	—
Reclassification of prior service credit relating to other postretirement benefits into earnings	—	—	—	1
	(3)	28	(25)	12
Comprehensive income (loss)	$ (6)	$ (507)	$ 14	$ 62

The accompanying notes are an integral part of these consolidated financial statements.

PANHANDLE EASTERN PIPE LINE COMPANY, LP

CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL
(Dollars in millions)

	Partners' Capital	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Predecessor				
Balance, December 31, 2011	$ 1,809	$ (16)	$ 847	$ 2,640
Equity-based compensation	—	—	2	2
Restricted stock issuances	—	—	(3)	(3)
Purchase of treasury stock	—	—	(1,450)	(1,450)
Net income	40	—	10	50
Other comprehensive income, net of tax	—	3	9	12
Balance, March 25, 2012	$ 1,849	$ (13)	$ (585)	$ 1,251
Successor				
Balance, March 26, 2012	$ 3,962	$ —	$ (49)	$ 3,913
Dividends paid to Southern Union stockholders	—	—	(65)	(65)
Capital contributions	—	—	166	166
Net income (loss)	88	—	(49)	39
Other comprehensive loss, net of tax	—	(9)	(16)	(25)
Balance, December 31, 2012	4,050	(9)	(13)	4,028
Dividends paid to Southern Union stockholders	—	—	(313)	(313)
Sales of MGE and NEG, net of tax	—	—	12	12
SUGS Contribution	—	—	(135)	(135)
Net loss	(499)	—	(36)	(535)
Other comprehensive income (loss), net of tax	—	12	(1)	11
Balance, December 31, 2013	3,551	3	(486)	3,068
Equity-based compensation	1	—	—	1
Distribution to partners	(102)	—	—	(102)
Lake Charles LNG Transaction	(20)	—	(23)	(43)
Panhandle Merger	(502)	(1)	503	—
Net income (loss)	(9)	—	6	(3)
Other	6	—	—	6
Other comprehensive loss, net of tax	—	(2)	—	(2)
Balance, December 31, 2014	$ 2,925	$ —	$ —	$ 2,925

The accompanying notes are an integral part of these consolidated financial statements.

PANHANDLE EASTERN PIPE LINE COMPANY, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in millions)

	Successor			Predecessor
	Year Ended December 31, 2014	Year Ended December 31, 2013	Period from Acquisition (March 26, 2012) to December 31, 2012	Period from January 1, 2012 to March 25, 2012
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income (loss)	$ (3)	$ (535)	$ 39	$ 50
Reconciliation of net income to net cash provided by operating activities:				
Depreciation and amortization (including discontinued operations)	130	189	206	57
Goodwill impairment	—	689	—	—
Deferred income taxes	(139)	181	90	23
Provision for bad debts	—	7	3	1
Amortization included in interest expense	(22)	(30)	(25)	1
Unrealized (gain) loss on derivatives	(25)	(52)	12	—
Non-cash compensation expense	5	6	—	2
Equity in (earnings) losses of unconsolidated affiliates	12	(15)	7	(16)
Distributions from unconsolidated affiliates	6	15	1	—
Net gain on curtailment of OPEB plans	—	—	(15)	—
Other non-cash	1	20	12	—
Changes in operating assets and liabilities, net of merger impacts	192	(159)	(178)	79
Net cash flows provided by operating activities	157	316	152	197
CASH FLOWS FROM INVESTING ACTIVITIES:				
Proceeds from SUGS Contribution	—	482	—	—
Proceeds from sale of MGE assets, net of transaction costs	—	1,008	—	—
Proceeds from Citrus Merger	—	—	—	1,895
Proceeds from affiliates	20	—	—	37
Capital expenditures	(109)	(250)	(238)	(60)
Distributions from unconsolidated affiliates in excess of cumulative earnings	65	39	6	—
Other	(16)	5	(1)	(2)
Net cash flows (used in) provided by investing activities	(40)	1,284	(233)	1,870
CASH FLOWS FROM FINANCING ACTIVITIES:				
Distributions to partners	(102)	(313)	(65)	(19)
Capital contribution from ETE	—	—	166	—
Issuance of loans from affiliates	—	1,669	55	—
Repayments of loans from affiliates	—	(975)	(55)	—
Issuance of long-term debt	—	—	—	455
Repayment of long-term debt	—	(1,795)	—	(1,048)
Net change in revolving credit facilities	—	(210)	(2)	12
Purchase of treasury stock	—	—	—	(1,450)
Other	—	(8)	(6)	(4)
Net cash flows (used in) provided by financing activities	(102)	(1,632)	93	(2,054)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	15	(32)	12	13
CASH AND CASH EQUIVALENTS, beginning of period	17	49	37	24
CASH AND CASH EQUIVALENTS, end of period	$ 32	$ 17	$ 49	$ 37

The accompanying notes are an integral part of these consolidated financial statements.

PANHANDLE EASTERN PIPE LINE COMPANY, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Tabular dollar amounts are in millions)

1. OPERATIONS AND ORGANIZATION:

Panhandle and its subsidiaries are primarily engaged in the interstate transportation and storage of natural gas and are subject to the rules and regulations of the FERC. The Company's entities include the following:

- PEPL, which is wholly-owned by SUG Holding Company, an indirect wholly-owned subsidiary of ETP;
- Trunkline, a direct wholly-owned subsidiary of PEPL;
- Sea Robin, an indirect wholly-owned subsidiary of PEPL; and
- Southwest Gas, a direct wholly-owned subsidiary of PEPL.

The Company's operations currently consist of interstate pipelines that transport natural gas from the Gulf of Mexico, South Texas and the panhandle regions of Texas and Oklahoma to major U.S. markets in the Midwest and Great Lakes regions, as well as owning underground storage capacity.

Southern Union Panhandle LLC, an indirect wholly-owned subsidiary of ETP, serves as the general partner of PEPL and owns a 1% general partnership interest in PEPL. ETP also indirectly owns a 99% limited partnership interest in PEPL.

See Note 3 for information related to the Panhandle Merger. We have accounted for this transaction as a reorganization of entities under common control; therefore, the consolidated financial statements of the Company were retrospectively adjusted to consolidate Southern Union for all periods. As a result of this retrospective consolidation, the Company's consolidated results of operations for the year ended December 31, 2013, the period from March 26 to December 31, 2012 and the period from January 1 to March 25, 2012 include Southern Union's former natural gas gathering and processing operations, which were contributed to an affiliate in 2013 as discussed in Note 3, and Southern Union's former local distribution operations, which were sold in 2013 and were presented as discontinued operations as discussed in Note 3.

Certain prior period amounts have been reclassified to conform to the 2014 presentation. These reclassifications had no impact on net income or total equity.

Lake Charles LNG was previously named Trunkline LNG Company, LLC, and changed its name in September 2014 to Lake Charles LNG Company, LLC. All references to this company throughout this document reflects the new name of the company, regardless of whether the disclosure relates to periods or events prior to the dates of the name change.

2. ESTIMATES, SIGNIFICANT ACCOUNTING POLICIES AND BALANCE SHEET DETAIL:

Basis of Presentation. The Company's consolidated financial statements have been prepared in accordance with GAAP.

The Company is subject to regulation by certain state and federal authorities. The Company has accounting policies under GAAP that do not conform to authoritative guidance which are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The Company does not apply regulatory-based accounting policies, primarily due to the level of discounting from tariff rates and its inability to recover specific costs. If regulatory-based accounting policies were applied, certain transactions would be recorded differently, including, among others, recording of regulatory assets, the capitalization of an equity component of invested funds on regulated capital projects and depreciation differences. The Company periodically reviews its level of discounting and negotiated rate contracts, the length of rate moratoriums and other related factors to determine if the regulatory-based authoritative guidance should be applied.

Principles of Consolidation. The consolidated financial statements include the accounts of all majority-owned subsidiaries, after eliminating significant intercompany transactions and balances. Investments in which the Company has significant influence over the operations of the investee are accounted for using the equity method.

Business Combination Accounting. Southern Union's March 26, 2012 merger transaction with ETE was accounted for by ETE using business combination accounting. Under this method, the purchase price paid by the acquirer is allocated to the assets acquired and liabilities assumed as of the acquisition date based on their fair value. By the application of "push-down" accounting, Southern Union and PEPL's assets, liabilities and partners' capital were accordingly adjusted to fair value on March 26, 2012. Determining the fair value of certain assets and liabilities assumed is judgmental in nature and often involves the use of significant estimates and assumptions. See Note 3 for a discussion of the estimated fair values of assets and liabilities recorded in connection with the ETE Merger.

Due to the application of "push-down" accounting, the Company's financial statements and certain footnote disclosures are presented in two distinct periods to indicate the application of two different bases of accounting. Periods prior to March 26, 2012 are identified herein as "Predecessor," while periods subsequent to the ETE Merger are identified as "Successor."

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

New Accounting Pronouncements. In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers (Topic 606)* ("ASU 2014-09"), which clarifies the principles for recognizing revenue based on the core principle that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period, with earlier adoption not permitted. ASU 2014-09 can be adopted either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment as of the date of adoption. The Partnership is currently evaluating the impact, if any, that adopting this new accounting standard will have on our revenue recognition policies.

In April 2014, the FASB issued Accounting Standards Update No. 2014-08, *Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity* ("ASU 2014-08"), which changed the requirements for reporting discontinued operations. Under ASU 2014-08, a disposal of a component of an entity or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has or will have a major effect on an entity's operations and financial results. ASU 2014-08 is effective for all disposals or classifications as held for sale of components of an entity that occur within fiscal years beginning after December 15, 2014, and early adoption is permitted. We expect to adopt this standard for the year ending December 31, 2015. ASU 2014-08 could have an impact on whether transactions will be reported in discontinued operations in the future, as well as the disclosures required when a component of an entity is disposed.

Cash and Cash Equivalents. Cash equivalents consist of highly liquid investments, which are readily convertible into cash and have original maturities of three months or less.

We place our cash deposits and temporary cash investments with high credit quality financial institutions. At times, our cash and cash equivalents may be uninsured or in deposit accounts that exceed the Federal Deposit Insurance Corporation insurance limit.

Non-cash investing and financing activities and supplemental cash flow information are as follows:

	Successor			Predecessor
	Year Ended December 31, 2014	Year Ended December 31, 2013	Period from Acquisition (March 26, 2012) to December 31, 2012	Period from January 1, 2012 to March 25, 2012
NON-CASH INVESTING ACTIVITIES:				
Contribution from affiliate	$ 376	$ —	$ —	$ —
SUPPLEMENTAL CASH FLOW INFORMATION:				
Accrued capital expenditures	$ 15	$ 13	$ 101	$ 9
Cash paid for interest, net of interest capitalized	$ 75	$ 142	$ 132	$ 39

Inventories. System natural gas and operating supplies consist of natural gas held for operations and materials and supplies, both of which are carried at the lower of weighted average cost or market, while natural gas owed back to customers is valued at market. The natural gas held for operations that the Company does not expect to consume in its operations in the next twelve months is reflected in non-current assets.

The following table presents the components of inventory:

	December 31,	
	2014	2013
Natural gas [1]	$ 105	$ 184
Materials and supplies	14	19
	$ 119	$ 203

(1) Natural gas volumes held for operations at December 31, 2014 and 2013 were 34.3 TBtu and 42.8 TBtu, respectively.

Natural Gas Imbalances. Natural gas imbalances occur as a result of differences in volumes of natural gas received and delivered. The Company records natural gas imbalance in-kind receivables and payables at cost or market, based on whether net imbalances have reduced or increased system natural gas balances, respectively. Net imbalances that have reduced system natural gas are valued at the cost basis of the system natural gas, while net imbalances that have increased system natural gas and are owed back to customers are priced, along with the corresponding system natural gas, at market.

Fuel Tracker. The fuel tracker is the cumulative balance of compressor fuel volumes owed to the Company by its customers or owed by the Company to its customers. The customers, pursuant to each pipeline's tariff and related contracts, provide all compressor fuel to the pipeline based on specified percentages of the customer's natural gas volumes delivered into the pipeline. The percentages are designed to match the actual natural gas consumed in moving the natural gas through the pipeline facilities, with any difference between the volumes provided versus volumes consumed reflected in the fuel tracker. The tariff of Trunkline Gas, in conjunction with the customers' contractual obligations, allows the Company to record an asset and direct bill customers for any fuel ultimately under-recovered. The other FERC-regulated Panhandle entities record an expense when fuel is under-recovered or record a credit to expense to the extent any under-recovered prior period balances are subsequently recouped as they do not have such explicit billing rights specified in their tariffs. Liability accounts are maintained for net volumes of compressor fuel natural gas owed to customers collectively. The pipelines' fuel reimbursement is in-kind and non-discountable.

Property, Plant and Equipment.

Additions. Ongoing additions of property, plant and equipment are stated at cost. The Company capitalizes all construction-related direct labor and material costs, as well as indirect construction costs. Such indirect construction costs primarily include capitalized interest costs (more fully described below in the "Interest Cost Capitalized" accounting policies disclosure) and labor and related costs of departments associated with supporting construction activities. The indirect capitalized labor and related costs are largely based upon results of periodic time studies or management reviews of time allocations, which provide an estimate of time spent supporting construction projects. The cost of replacements and betterments that extend the useful life of property, plant and equipment is also capitalized. The cost of repairs and replacements of minor property, plant and equipment items is charged to expense as incurred.

Retirements. When ordinary retirements of property, plant and equipment occur, the original cost less salvage value is removed by a charge to accumulated depreciation and amortization, with no gain or loss recorded. When entire regulated operating units of property, plant and equipment are retired or sold, the original cost less salvage value and related accumulated depreciation and amortization accounts are removed, with any resulting gain or loss recorded in earnings.

Depreciation. The Company computes depreciation expense using the straight-line method.

Interest Cost Capitalized. The Company capitalizes interest on certain qualifying assets that are undergoing activities to prepare them for their intended use. Interest costs incurred during the construction period are capitalized and amortized over the life of the assets.

For additional information, see Note 12.

Asset Impairment. An impairment loss is recognized when the carrying amount of a long-lived asset used in operations is not recoverable and exceeds its fair value. The carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. A long-lived asset is tested for recoverability whenever events or changes in circumstances indicate that its carrying amount may not be recoverable.

Goodwill. Goodwill resulting from a purchase business combination is not amortized, but instead is tested for impairment at the Company's reporting unit level at least annually during the fourth quarter by applying a fair-value based test. The annual impairment test is updated if events or circumstances occur that would more likely than not reduce the fair value of the reporting unit below its book carrying value.

During the fourth quarter of 2013, we performed a goodwill impairment test on our Lake Charles LNG reporting unit. In accordance with GAAP, we performed step one of the goodwill impairment test and determined that the estimated fair value of the Lake Charles LNG reporting unit was less than its carrying amount primarily due to changes related to (i) the structure and capitalization of the planned LNG export project at Lake Charles LNG's Lake Charles facility, (ii) an analysis of current macroeconomic factors, including global natural gas prices and relative spreads, as of the date of our assessment, (iii) judgments regarding the prospect of obtaining regulatory approval for a proposed LNG export project and the uncertainty associated with the timing of such approvals, and (iv) changes in assumptions related to potential future revenues from the import facility and the proposed export facility. An assessment of these factors in the fourth quarter of 2013 led to a conclusion that the estimated fair value of the Lake Charles LNG reporting unit was less than its carrying amount. We then applied the second step in the goodwill impairment test, allocating the estimated fair value of the reporting unit among all of the assets and liabilities of the reporting unit in a hypothetical purchase price allocation. The assets and liabilities of the reporting unit had recently been measured at fair value in 2012 as a result of the acquisition of Southern Union, and those estimated fair values had been recorded at the reporting unit through the application of "push-down" accounting. For purposes of the hypothetical purchase price allocation used in the goodwill impairment test, we estimated the fair value of the assets and liabilities of the reporting unit in a manner similar to the original purchase price allocation. In allocating value to the property, plant and equipment, we used current replacement costs adjusted for assumed depreciation. We also included the estimated fair value of working capital and identifiable intangible assets in the reporting unit. We adjusted deferred income taxes based on these estimated fair values. Based on this hypothetical purchase price allocation, estimated goodwill was $184 million, which was less than the balance of $873 million that had originally been recorded by the reporting unit through "push-down" accounting in 2012. As a result, we recorded a goodwill impairment of $689 million during the fourth quarter of 2013.

Related Party Transactions. Related party expenses primarily include payments for services provided by ETE, ETP and other affiliates. See Note 4 for additional information on related party transactions.

PEPL and certain of its subsidiaries are not treated as separate taxpayers for federal and certain state income tax purposes. Instead, the Company's income is taxable to its parent, SUG Holding Company. The Company has entered into a tax sharing agreement with SUG Holding Company pursuant to which the Company will be required to make payments to SUG Holding Company in order to reimburse SUG Holding Company for federal and state taxes that it pays on the Company's income, or to receive payments from SUG Holding Company to the extent that tax losses generated by the Company are utilized by SUG Holding Company. In addition, the Company's subsidiaries that are corporations are included in consolidated and combined federal and state income tax returns filed by SUG Holding Company. The Company's liability generally is equal to the liability that the Company and its subsidiaries would have incurred based upon the Company's taxable income if the Company was a taxpayer filing separately from SUG Holding Company, except that the Company will receive credit under an intercompany note for any increased liability resulting from its tax basis in its assets having been reduced as a result of the like-kind exchange under Section 1031 of the Internal Revenue Code of 1986, as amended. The tax sharing agreement may be amended from time to time.

Investments in Unconsolidated Affiliates. Investments in unconsolidated affiliates over which the Company may exercise significant influence are accounted for using the equity method. Any excess of the Company's investment in affiliates, as compared to its share of the underlying equity, that is not recognized as goodwill is amortized over the estimated economic service lives of the underlying assets. Other investments over which the Company may not exercise significant influence are accounted for under the cost method. A loss in value of an investment, other than a temporary decline, is recognized in earnings. Evidence of a loss in value might include, but would not necessarily be limited to, absence of an ability to recover the carrying amount of the investment or inability of the investee to sustain an earnings capacity that would justify the carrying amount of the investment. A current fair value of an investment that is less than its carrying amount may indicate a loss in value of the investment. All of the above factors are considered in the Company's review of its equity method investments. See Note 5 for further information.

Environmental Expenditures. Environmental expenditures that relate to an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Environmental expenditures relating to current or future revenues are expensed or capitalized as appropriate. Liabilities are recorded when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. Remediation obligations are not discounted because the timing of future cash flow streams is not predictable.

Revenues. The Company's revenues from transportation and storage of natural gas are based on capacity reservation charges and, to a lesser extent, commodity usage charges. Reservation revenues are based on contracted rates and capacity reserved by the customers and are recognized monthly. Revenues from commodity usage charges are also recognized monthly, based on the volumes received from or delivered for the customer, based on the tariff of that particular Panhandle entity, with any differences in volumes received and delivered resulting in an imbalance. Volume imbalances generally are settled in-kind with no impact on revenues, with the exception of Trunkline, which settles certain imbalances in cash pursuant to its tariff, and records gains and losses on such cashout sales as a component of revenue, to the extent not owed back to customers. Because Panhandle is subject to FERC regulation, revenues collected during the pendency of a rate proceeding may be required by FERC to be refunded in the final order. Panhandle establishes reserves for such potential refunds, as appropriate.

Accounts Receivable and Allowance for Doubtful Accounts. The Company has a concentration of customers in the electric and gas utility industries as well as oil and natural gas producers and municipalities. This concentration of customers may impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic or other conditions. The Company manages trade credit risk to mitigate credit losses and exposure to uncollectible trade receivables. Prospective and existing customers are reviewed regularly for creditworthiness based upon pre-established standards consistent with FERC filed tariffs to manage credit risk within approved tolerances. Customers that do not meet minimum credit standards are required to provide additional credit support in the form of a letter of credit, prepayment, or other forms of security.

The Company establishes an allowance for doubtful accounts on trade receivables based on the expected ultimate recovery of these receivables and considers many factors including historical customer collection experience, general and specific economic trends, and known specific issues related to individual customers, sectors, and transactions that might impact collectability. Increases in the allowance are recorded as a component of operating expenses; reductions in the allowance are recorded when receivables are subsequently collected or written-off. Past due receivable balances are written-off when the Company's efforts have been unsuccessful in collecting the amount due.

Amounts related to the allowance for doubtful accounts were not material as of and during the years ended December 31, 2014, 2013 and 2012.

The following table presents the relative contribution to the Company's total operating revenue from continuing operations of each customer that comprised at least 10% of its operating revenues:

	Successor			Predecessor
	Year Ended December 31, 2014	Year Ended December 31, 2013	Period from Acquisition (March 26, 2012) to December 31, 2012	Period from January 1, 2012 to March 25, 2012
Phillips 66 Company(1)	—%	10%	28%	35%
BG Energy Holdings LTD(2)	—	22	14	14
Ameren Corporation	11	6	3	4
Other top 10 customers	40	20	22	21
Remaining customers	49	42	33	26
Total percentage	100%	100%	100%	100%

(1) SUGS, which was deconsolidated on April 30, 2013, had contracted to sell its entire owned or controlled output of NGL equity volumes to Phillips 66. Pricing for the NGL equity volumes sold to Phillips 66 throughout the contract period was OPIS pricing based at Mont Belvieu, Texas delivery points.

(2) BG Energy Holdings LTD is the sole customer of Lake Charles LNG, which was deconsolidated effective January 1, 2014. See Note 3.

Accumulated Other Comprehensive Income. The main components of comprehensive loss that relate to the Company are net earnings, unrealized gain (loss) on hedging activities and unrealized actuarial gain (loss) and prior service credits (cost) on pension and other postretirement benefit plans. For more information, see Note 6.

Retirement Benefits. Employers are required to recognize in their balance sheets the overfunded or underfunded status of defined benefit pension and other postretirement plans, measured as the difference between the fair value of the plan assets and the benefit obligation (the projected benefit obligation for pension plans and the accumulated postretirement benefit obligation for other postretirement plans). Each overfunded plan is recognized as an asset and each underfunded plan is recognized as a liability. Employers must recognize the change in the funded status of the plan in other comprehensive income in partners' capital in the year in which the change occurs. See Note 8 for additional related information.

Derivatives and Hedging Activities. All derivatives are recognized on the consolidated balance sheet at their fair value. On the date the derivative contract is entered into, the Company designates the derivative as (i) a hedge of the fair value of a recognized asset or liability or of an unrecognized firm commitment (a fair value hedge); (ii) a hedge of a forecasted transaction or the variability of cash flows to be received or paid in conjunction with a recognized asset or liability (a cash flow hedge); or (iii) an instrument that is held for trading or non-hedging purposes (a trading or economic hedging instrument). For derivatives treated as a fair value hedge, the effective portion of changes in fair value is recorded as an adjustment to the hedged item. The ineffective portion of a fair value hedge is recognized in earnings. Upon termination of a fair value hedge of a debt instrument, the resulting gain or loss is amortized to earnings through the maturity date of the debt instrument. For derivatives treated as a cash flow hedge, the effective portion of changes in fair value is recorded in accumulated other comprehensive income until the related hedged items impact earnings. Any ineffective portion of a cash flow hedge is reported in current-period earnings. For derivatives treated as trading or economic hedging instruments, changes in fair value are reported in current-period earnings. Fair value is determined based upon quoted market prices and pricing models using assumptions that market participants would use. See Note 10 for information related to derivative instruments and hedging activities.

Stock-Based Compensation. The Company measured all employee stock-based compensation using a fair value method and recorded the related expense in the consolidated statement of operations. All outstanding stock awards vested and were settled in 2012 in connection with the ETE Merger on March 26, 2012.

Fair Value Measurement. Fair value is 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. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about nonperformance risk, which is primarily comprised of credit risk (both the Company's own credit risk and counterparty credit risk) and the risks inherent in the inputs to any applicable valuation techniques. The Company places more weight on current market information concerning credit risk (e.g. current credit default swap rates) as opposed to historical information (e.g. historical default probabilities and credit ratings). These inputs can be readily observable, market corroborated, or generally unobservable. The Company endeavors to utilize the best available information, including valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. A three-tier fair value hierarchy, which prioritizes the inputs used to measure fair value, is as follows:

- Level 1 – Observable inputs such as quoted prices in active markets for identical assets or liabilities;

- Level 2 – Observable inputs such as: (i) quoted prices for similar assets or liabilities in active markets; (ii) quoted prices for identical or similar assets or liabilities in markets that are not active and do not require significant adjustment based on unobservable inputs; or (iii) valuations based on pricing models, discounted cash flow methodologies or similar techniques where significant inputs (e.g., interest rates, yield curves, etc.) are derived principally from observable market data, or can be corroborated by observable market data, for substantially the full term of the assets or liabilities; and

- Level 3 – Unobservable inputs, including valuations based on pricing models, discounted cash flow methodologies or similar techniques where at least one significant model assumption or input is unobservable. Unobservable inputs are used to the extent that observable inputs are not available and reflect the Company's own assumptions about the assumptions market participants would use in pricing the assets or liabilities. Unobservable inputs are based on the best information available in the circumstances, which might include the Company's own data.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of these assets and liabilities and their placement within the fair value hierarchy.

See Note 8 and Note 11 for additional information regarding the assets and liabilities of the Company measured on a recurring and nonrecurring basis, respectively.

Asset Retirement Obligations. Legal obligations associated with the retirement of long-lived assets are recorded at fair value at the time the obligations are incurred, if a reasonable estimate of fair value can be made. Present value techniques are used which reflect assumptions such as removal and remediation costs, inflation, and profit margins that third parties would demand to settle the amount of the future obligation. The Company did not include a market risk premium for unforeseeable circumstances in its fair value estimates because such a premium could not be reliably estimated. Upon initial recognition of the liability, costs are capitalized as a part of the long-lived asset and allocated to expense over the useful life of the related asset. The liability is accreted to its present value each period with accretion being recorded to operating expense with a corresponding increase in the carrying amount of the liability. To the extent the Company is permitted to collect and has reflected in its financials amounts previously collected from customers and expensed, such amounts serve to reduce what would be reflected as capitalized costs at the initial establishment of an ARO.

See Note 13 for additional related information.

Income Taxes. Income taxes are accounted for under the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in earnings in the period that includes the enactment date. Valuation allowances are established when necessary to reduce deferred tax assets to the amounts more likely than not to be realized.

The determination of the provision for income taxes requires significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items and the probability of sustaining uncertain tax positions. The benefits of uncertain tax positions are recorded in our financial statements only after determining a more-likely-than-not probability that the uncertain tax positions will withstand challenge, if any, from taxing authorities. When facts and circumstances change, we reassess these probabilities and record any changes through the provision for income taxes.

As a limited partnership, the Company is treated as a disregarded entity for federal income tax purposes. Accordingly, the Company and its subsidiaries are not treated as separate taxpayers; instead, their income is directly taxable to SUG Holding Company, a wholly-owned subsidiary of ETP Holdco. Prior to the Panhandle Merger, the Company's income was directly taxable to Southern Union, a wholly-owned subsidiary of ETP Holdco. Upon completion of the ETP Holdco Transaction on October 5, 2012, Southern Union became a member of a new federal consolidated tax return filing group of which ETP Holdco is the parent company. As a result of the ETP Holdco Transaction, Southern Union entered into a tax sharing agreement with ETP Holdco. The Company's tax sharing arrangement with SUG Holding Company is similar to the arrangement with Southern Union, resulting in the Company paying its share of taxes based on taxable income, which will generally equal the liability that the Company would have incurred as a separate taxpayer.

Commitments and Contingencies. The Company is subject to proceedings, lawsuits and other claims related to environmental and other matters. Accounting for contingencies requires significant judgment by management regarding the estimated probabilities and ranges of exposure to potential liability. For further discussion of the Company's commitments and contingencies, see Note 14.

3. MERGERS, DECONSOLIDATIONS, AND RELATED TRANSACTIONS:

Pending Transaction

Regency Merger

In January 2015, ETP and Regency entered into a definitive merger agreement pursuant to which ETP will acquire Regency. Under the terms of the definitive merger agreement, holders of Regency common units will receive 0.4066 ETP Common Units for each Regency common unit. Regency unitholders will also receive at closing an additional $0.32 per common unit in the form of ETP Common Units (based on the price for ETP Common Units prior to the merger closing). The transaction is subject to other customary closing conditions including approval by Regency's unitholders and is expected to close in the second quarter of 2015.

2014 Transactions

Panhandle Merger

On January 10, 2014, the Company consummated a merger with Southern Union, the indirect parent of the Company, and PEPL Holdings, the sole limited partner of the Company, pursuant to which each of Southern Union and PEPL Holdings, a wholly-owned subsidiary of Southern Union, were merged with and into the Company (the "Panhandle Merger"), with the Company surviving the Panhandle Merger. In connection with the Panhandle Merger, the Company assumed Southern Union's obligations under its 7.6% Senior Notes due 2024, 8.25% Senior Notes due 2029 and Floating Rate Junior Subordinated Notes due 2066. At the time of the Panhandle Merger, Southern Union did not have material operations of its own, other than its ownership of the Company and noncontrolling interest in PEI Power II, LLC, Regency (31.4 million common units and 6.3 million Class F Units) and ETP (2.2 million common units). In connection with the Panhandle Merger, the Company also assumed PEPL Holdings' guarantee of $600 million of Regency senior notes.

Lake Charles LNG Transaction

On February 19, 2014, Panhandle transferred to ETP all of the interests in Lake Charles LNG, the entity that owns a LNG regasification facility in Lake Charles, Louisiana, in exchange for the cancellation of a $1.09 billion note payable to ETP that was assumed by the Company in the merger with Southern Union on January 10, 2014. Also on February 19, 2014, ETE and ETP completed the transfer to ETE of Lake Charles LNG from ETP in exchange for the redemption by ETP of 18.7 million ETP common units held by ETE. The transaction was effective as of January 1, 2014, at which time Panhandle deconsolidated Lake Charles LNG, including goodwill of $184 million and intangible assets of $50 million related to Lake Charles LNG. The results of Lake Charles LNG's operations have not been presented as discontinued operations and Lake Charles LNG's assets and liabilities have not been presented as held for sale in the Company's consolidated financial statements due to the expected continuing involvement among the entities.

2013 Transactions

Sale of Southern Union's Distribution Operations

In September 2013, Southern Union completed its sale of the assets of MGE for an aggregate purchase price of $975 million, subject to customary post-closing adjustments. In December 2013, Southern Union completed its sale of the assets of NEG for cash proceeds of $40 million, subject to customary post-closing adjustments, and the assumption of $20 million of debt.

MGE and NEG have been classified as discontinued operations in the consolidated statements of operations.

Summarized financial information for MGE and NEG is as follows:

	Successor		Predecessor
	Year Ended December 31, 2013	Period from Acquisition (March 26, 2012) to December 31, 2012	Period from January 1, 2012 to March 25, 2012
Revenue from discontinued operations	415	324	190
Net income of discontinued operations, excluding effect of taxes and overhead allocations	65	43	27

SUGS Contribution

On April 30, 2013, Southern Union completed its contribution to Regency of all of the issued and outstanding membership interest in Southern Union Gathering Company, LLC, and its subsidiaries, including SUGS (the "SUGS Contribution"). The general partner and IDRs of Regency are owned by ETE. The consideration paid by Regency in connection with this transaction consisted of (i) the issuance of approximately 31.4 million Regency common units to Southern Union, (ii) the issuance of approximately 6.3 million Regency Class F units to Southern Union, (iii) the distribution of $463 million in cash to Southern Union, net of closing adjustments, and (iv) the payment of $30 million in cash to a subsidiary of ETP. This transaction was between commonly controlled entities; therefore, the amounts recorded in the consolidated balance sheet for the investment in Regency and the related deferred tax liabilities were based on the historical book value of SUGS. In addition, PEPL Holdings provided a guarantee of collection with respect to the payment of the principal amounts of Regency's debt related to the SUGS Contribution. The Regency Class F units have the same rights, terms and conditions as the Regency common units, except that the Company, as successor to Southern Union, will not receive distributions on the Regency Class F units for the first eight consecutive quarters following the closing, and the Regency Class F units will thereafter automatically convert into Regency common units on a one-for-one basis.

ETP's Acquisition of ETE's ETP Holdco Interest

On April 30, 2013, ETP acquired ETE's 60% interest in ETP Holdco, the entity formed by ETP and ETE in 2012 (as discussed under "ETP Holdco Transaction" below) to own the equity interests in Southern Union and Sunoco, Inc.. As a result of this transaction, ETP now owns 100% of ETP Holdco. ETP controlled ETP Holdco prior to this acquisition; therefore, the transaction did not constitute a change of control.

2012 Transactions

ETE Merger

On March 26, 2012, ETE completed its acquisition of Southern Union. Southern Union was the surviving entity in the merger and operated as a wholly-owned subsidiary of ETE until the Panhandle Merger in 2014. See below for discussion of ETP Holdco Transaction and ETE's contribution of Southern Union to ETP Holdco.

Under the terms of the merger agreement, Southern Union stockholders received a total of 56,982,160 ETE Common Units and a total of approximately $3.01 billion in cash. Effective with the closing of the transaction, Southern Union's common stock was no longer publicly traded.

In connection with the ETE Merger on March 26, 2012, ETP completed the acquisition of CrossCountry, a subsidiary of Southern Union which owned an indirect 50% interest in Citrus, the owner of FGT. The total merger consideration was approximately $2.0 billion, consisting of approximately $1.9 billion in cash and approximately 2.3 million ETP Common Units.

ETP Holdco Transaction

Immediately following the closing of ETP's acquisition of Sunoco, Inc. in 2012, ETE contributed its interest in Southern Union into ETP Holdco, an ETP-controlled entity, in exchange for a 60% equity interest in ETP Holdco. In conjunction with ETE's contribution, ETP contributed its interest in Sunoco, Inc. to ETP Holdco and retained a 40% equity interest in ETP Holdco. Pursuant to a stockholders agreement between ETE and ETP, ETP controlled ETP Holdco. This transaction did not result in a new basis of accounting for Southern Union or Panhandle.

Allocation of Consideration Transferred

The ETE Merger was accounted for using business combination accounting under applicable accounting principles. Business combination accounting requires, among other things, that assets acquired and liabilities assumed be recognized on the balance sheet at their fair values as of the acquisition date. The table below represents the amounts allocated to Southern Union's tangible and intangible assets and liabilities as of March 26, 2012 based upon management's estimate of their respective fair values. The goodwill resulting from the ETE Merger was primarily due to expected commercial and operational synergies and is not deductible for tax purposes.

Cash and cash equivalents	$ 37
Other current assets	519
Property and equipment	6,242
Goodwill	2,497
Identified intangibles [1]	55
Other non-current assets	290
Long-term debt, including current portion	(3,334)
Deferred income taxes	(1,419)
Other liabilities	(974)
Total fair value of partners' capital	$ 3,913

[1] Identified intangibles will be amortized over a life of approximately 17.5 years and are included in Other non-current assets in the consolidated balance sheets.

As a result of the ETE Merger, we recognized $77 million and $19 million of merger-related costs during the periods from March 26, 2012 to December 31, 2012 and January 1, 2012 to March 25, 2012, respectively. Such expenses include legal and other outside service costs, charges resulting from employment agreements with certain executives that provided for compensation when their employment was terminated and severance costs associated with administrative headcount reductions. These expenses were included in operating, maintenance, and general expenses in the consolidated statement of operations.

The Company also recognized a $15 million net gain due to the curtailment of certain other postretirement employee benefit plans in 2012. See Note 8 for more information on the curtailment.

4. RELATED PARTY TRANSACTIONS:

The following table provides a summary of the related party balances included in the consolidated balance sheets:

	December 31, 2014	December 31, 2013
Non-current notes receivable from related party — ETP	$ —	$ 396
Accounts receivable from related companies [(1)]	$ 128	$ 64
Accounts payable to related companies [(2)]	$ 38	$ 181
Non-current note payable to related party — ETP	$ —	$ 1,090
Advances from affiliates	$ 51	$ —

(1) Accounts receivable from related companies reflected above primarily related to services provided for ETE, ETP and other affiliates.

(2) Accounts payable to related companies reflected above primarily related to payroll funding and various services provided by ETP and other affiliates.

The following tables provide a summary of related party activity included in our consolidated statements of operations:

	Successor			Predecessor
	Year Ended December 31, 2014	Year Ended December 31, 2013	Period from Acquisition (March 26, 2012) to December 31, 2012	Period from January 1, 2012 to March 25, 2012
Operating revenues [(1)]	$ 33	$ 56	$ 29	$ 4
Cost of natural gas and other energy	—	17	21	—
Operating, maintenance and general	49	71	125 [(2)]	14
Interest expense, net of interest capitalized	—	31	3	—
Interest income — affiliates	23	9	—	—
Equity in earnings (losses) of unconsolidated investments	(12)	15	(7)	16

(1) Represents transportation and storage revenues with ETC and Sunoco, Inc., subsidiaries of ETP, in the successor periods.

(2) Primarily represents corporate charges for employee expenses related to the ETE Merger offset by expenses attributable to services provided by Panhandle on behalf of other affiliate companies.

The following table provides a summary of distributions received from related parties:

	Successor			Predecessor
	Year Ended December 31, 2014	Year Ended December 31, 2013	Period from Acquisition (March 26, 2012) to December 31, 2012	Period from January 1, 2012 to March 25, 2012
Distributions related to investment in:				
ETP	$ 9	$ 8	$ 6	$ —
Regency	61	44	—	—

5. INVESTMENTS IN UNCONSOLIDATED AFFILIATES:

The Company’s investment in Regency consists of approximately 31.4 million Regency common units and approximately 6.3 million Regency Class F units that were issued to Southern Union as consideration for the SUGS Contribution. The Company’s investment represented approximately 8% and 100% of the total outstanding Regency common units and Class F units, respectively, at December 31, 2014. The Company’s investment in Regency is accounted for in our consolidated financial statements using the equity method, because the Company is presumed to have significant influence over Regency due to the affiliate relationship resulting from both entities being under the common control of ETE.

The following table presents aggregated selected income statement data for Regency (on a 100% basis for all periods presented).

	Years Ended December 31,		
	2014	2013	2012
Revenue	$ 4,951	$ 2,521	$ 2,000
Operating income (loss)	(17)	55	30
Net income (loss)	(142)	27	34

In addition to the equity method investment described above, we have other equity method investments which are not, individually or in the aggregate, significant to our consolidated financial statements.

6. COMPREHENSIVE INCOME:

The table below sets forth the tax amounts included in the respective components of other comprehensive income:

	Successor			Predecessor
	Year Ended December 31, 2014	Year Ended December 31, 2013	Period from Acquisition (March 26, 2012) to December 31, 2012	Period from January 1, 2012 to March 25, 2012
Income taxes included in other comprehensive income:				
Change in fair value of interest rate hedges	$ —	$ —	$ —	$ 2
Reclassification of unrealized loss on interest rate hedges into earnings	—	—	—	3
Change in fair value of commodity hedges	—	—	(2)	2
Reclassification of unrealized gain on commodity hedges into earnings	—	—	—	(1)
Actuarial gain (loss) relating to postretirement benefits	1	(15)	(13)	—
Reclassification of net actuarial loss and prior service credit relating to pension and other postretirement benefits into earnings	—	—	—	1
	$ 1	$ (15)	$ (15)	$ 7

The table below presents the components in accumulated other comprehensive income:

	December 31,	
	2014	2013
Other postretirement plan - net actuarial gain and prior service costs, net	$ —	$ 3
Total accumulated other comprehensive income, net of tax	$ —	$ 3

7. DEBT OBLIGATIONS:

The following table sets forth the debt obligations of the Company at the dates indicated:

	December 31, 2014	December 31, 2013
6.20% Senior Notes due 2017	$ 300	$ 300
8.125% Senior Notes due 2019	150	150
7.00% Senior Notes due 2018	400	400
7.6% Senior Notes due 2024	82	82
7.00% Senior Notes due 2029	66	66
8.25% Senior Notes due 2029	33	33
Floating Rate Junior Subordinated Notes due 2066	54	54
Note payable to related party - ETP	—	1,090
Other long term debt	6	7
Unamortized fair value adjustments	99	155
Total debt outstanding	1,190	2,337
Less: Current maturities of long-term debt	1	1
Total long-term debt, less current maturities	$ 1,189	$ 2,336

Based on the estimated borrowing rates currently available to the Company and its subsidiaries for loans with similar terms and average maturities, the aggregate fair value of the Company's consolidated debt obligations at December 31, 2014 and 2013 was $1.24 billion and $2.38 billion, respectively. As of December 31, 2014 and 2013, the aggregate carrying amount of the Company's consolidated debt obligations was $1.19 billion and $2.34 billion, respectively. The fair value of the Company's consolidated debt obligations is a Level 2 valuation based on the observable inputs used for similar liabilities.

As of December 31, 2014, the Company has scheduled long-term debt principal payments as follows:

Years Ended December 31,	
2015	$ —
2016	—
2017	300
2018	400
2019	150
Thereafter	241
Total	$ 1,091

Assumption of Southern Union Debt

In connection with the consummation of the Panhandle Merger, Panhandle assumed Southern Union's long-term debt obligations. As of December 31, 2014, the long-term debt assumed in the Panhandle Merger consisted of $82 million in aggregate principal amount of 7.6% Senior Notes due 2024, $33 million in aggregate principal amount of 8.25% Senior Notes due 2029 and $54 million in aggregate principal amount of Floating Rate Junior Subordinated Notes due 2066 outstanding. The amounts recorded in the condensed consolidated balance sheet also reflected unamortized fair value adjustments, which were $99 million in the aggregate at December 31, 2014.

In connection with the Lake Charles LNG Transaction, the $1.09 billion note payable to ETP that was assumed by the Company in the merger with Southern Union on January 10, 2014 was canceled.

Floating Rate Junior Subordinated Notes

The interest rate on the remaining portion of Panhandle's $600 million junior subordinated notes due 2066 is a variable rate based upon the three-month LIBOR rate plus 3.0175%. The balance of the variable rate portion of the junior subordinated notes was $54 million at an effective interest rate of 3.26% at December 31, 2014.

Compliance With Our Covenants

The Company's notes are subject to certain requirements, such as the maintenance of a fixed charge coverage ratio and a leverage ratio, which if not maintained, restrict the ability of the Company to make certain payments and impose limitations on the ability of the Company to subject its property to liens. Other covenants impose limitations on restricted payments, including dividends and loans to affiliates, and additional indebtedness. As of December 31, 2014, the Company is in compliance with these covenants.

8. RETIREMENT BENEFITS:

Southern Union previously had defined benefit pension plans that covered employees of MGE and NEG. As discussed in Note 3, the assets of MGE and NEG were sold in 2013, prior to the Panhandle Merger; therefore, the pension plan obligations were never the responsibilities of the Company. As such, the disclosures related to these pension plans have been excluded.

Postretirement Benefit Plans

Postretirement benefits expense for the years ended December 31, 2014 and 2013 reflected the impact of changes the Company adopted as of September 30, 2013 to change its retiree medical benefits program effective January 1, 2014 which placed all retirees on a common cost sharing platform, subject to caps on annual company contributions toward retirees eligible for the plan. Postretirement benefits expense for the year ended December 31, 2012 reflected the impact of curtailment accounting as postretirement benefits for all active participants who did not meet certain criteria were eliminated. The Company previously had postretirement health care and life insurance plans (other postretirement plans) that covered substantially all employees.

Obligations and Funded Status

Other postretirement benefit liabilities are accrued on an actuarial basis during the years an employee provides services. The following tables contain information at the dates indicated about the obligations and funded status of the Company's other postretirement plans.

	December 31,	
	2014	2013
Change in benefit obligation:		
Benefit obligation at beginning of period	$ 25	$ 41
Service cost	—	—
Interest cost	1	1
Amendments	—	1
Actuarial (gain) loss	1	(16)
Benefits paid, net	(2)	(2)
Dispositions	(1)	—
Benefit obligation at end of period	$ 24	$ 25
Change in plan assets:		
Fair value of plan assets at beginning of period	$ 110	$ 96
Return on plan assets and other	4	8
Employer contributions	7	8
Benefits paid, net	(2)	(2)
Dispositions	(5)	—
Fair value of plan assets at end of period	$ 114	$ 110
Amount (overfunded) underfunded at end of period (1)	$ (90)	$ (85)
Amounts recognized in accumulated other comprehensive income (pre-tax basis) consist of:		
Net actuarial loss	$ (16)	$ (20)
Prior service cost	15	17
	$ (1)	$ (3)

(1) Underfunded balance is recognized as a non-current liability in the consolidated balance sheets. Overfunded balance is recognized as a non-current asset in the consolidated balance sheets.

Components of Net Periodic Benefit Cost

The following tables set forth the components of net periodic benefit cost of the Company's postretirement benefit plan for the periods presented:

	Successor			Predecessor
	Year Ended December 31, 2014	Year Ended December 31, 2013	Period from Acquisition (March 26, 2012) to December 31, 2012	Period from January 1, 2012 to March 25, 2012
Service cost	$ —	$ —	$ —	$ 1
Interest cost	1	1	1	1
Expected return on plan assets	(5)	(5)	(4)	(1)
Prior service credit amortization	1	1	—	(1)
Actuarial loss amortization	(1)	(1)	—	—
Curtailment recognition (1)	—	—	(15)	—
Net periodic benefit cost	$ (4)	$ (4)	$ (18)	$ —

(1) Subsequent to the ETE Merger, the Company amended certain of its other postretirement employee benefit plans to prospectively restrict participation in the plans for certain active employees. The plan amendments resulted in the plans becoming currently over-funded and, accordingly, the Company recorded a gross pre-tax curtailment gain of $75 million, $60 million of which is subject to refund to customers; thus, the net curtailment gain recognition was $15 million.

The estimated prior service cost for other postretirement plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost during 2015 is $1 million.

Assumptions. The weighted-average discount rate used in determining benefit obligations was 3.68% and 4.24% at December 31, 2014 and 2013, respectively.

The weighted-average assumptions used in determining net periodic benefit cost for the periods presented are shown in the table below:

	Successor			Predecessor
	Year Ended December 31, 2014	Year Ended December 31, 2013	Period from Acquisition (March 26, 2012) to December 31, 2012	Period from January 1, 2012 to March 25, 2012
Discount rate	4.29%	3.66%	4.02%	4.24%
Expected return on assets:				
Tax exempt accounts	7.00%	7.00%	7.00%	7.00%
Taxable accounts	4.50%	4.50%	4.50%	4.50%

The Company employs a building block approach in determining the expected long-term rate of return on the plans' assets with proper consideration for diversification and rebalancing. Historical markets are studied and long-term historical relationships between equities and fixed-income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors such as inflation and interest rates are evaluated before long-term market assumptions are determined. Peer data and historical returns are reviewed to check for reasonableness and appropriateness.

The assumed health care cost trend rates used to measure the expected cost of benefits covered by the plans are shown in the table below:

	December 31,	
	2014	2013
Health care cost trend rate	7.60%	8.06%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	4.90%	4.91%
Year that the rate reaches the ultimate trend rate	2021	2021

Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	One Percentage Point Increase	One Percentage Point Decrease
Effect on accumulated postretirement benefit obligation	$ 1	$ (1)

Plan Assets. The Company's overall investment strategy is to maintain an appropriate balance of actively managed investments while maintaining a high standard of portfolio quality and achieving proper diversification. To achieve diversity within its other postretirement plan asset portfolio, the Company has targeted the following asset allocations: equity of 25% to 35%, fixed income of 65% to 75% and cash and cash equivalents of up to 10%. These target allocations are monitored by the Investment Committee of ETP's Board of Directors in conjunction with an external investment advisor. On occasion, the asset allocations may fluctuate as compared to these guidelines as a result of Investment Committee actions.

The fair value of the Company's other postretirement plan assets at the dates indicated by asset category is as follows:

	December 31,	
	2014	2013
Cash and cash equivalents	$ 3	$ 3
Mutual fund [(1)]	111	107
Total	$ 114	$ 110

(1) This fund of funds invests primarily in a diversified portfolio of equity, fixed income and short-term mutual funds. As of December 31, 2014, the fund was primarily comprised of approximately 38% equities, 52% fixed income securities and 10% cash. As of December 31, 2013, the fund was primarily comprised of approximately 32% equities, 55% fixed income securities, 7% cash and 6% in other investments.

The other postretirement plan assets are classified as Level 1 assets within the fair-value hierarchy as their fair values are based on active market quotes. See Note 2 for information related to the framework used by the Company to measure the fair value of its other postretirement plan assets.

Contributions. The Company expects to make $8 million contributions to its other postretirement plans in 2015 and approximately $8 million annually thereafter until modified by rate case proceedings.

Benefit Payments. The Company's estimate of expected benefit payments, which reflect expected future service, as appropriate, in each of the next five years and in the aggregate for the five years thereafter are shown in the table below. The Company does not expect to receive any Medicare Part D subsidies in any future periods.

Years	Expected Benefit Payments
2015	$ 2
2016	2
2017	2
2018	1
2019	1
2020 – 2024	6

The Medicare Prescription Drug Act provides for a prescription drug benefit under Medicare ("Medicare Part D") as well as a federal subsidy to sponsors of retiree health plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare Part D. The Company was eligible for such subsidies through December 31, 2013. As a result of changes the Company made to the retiree medical plan effective January 1, 2014, the Company no longer receives such subsidy payments for coverage provided after December 31, 2013.

Defined Contribution Plan

The Company participates in ETP's defined contribution savings plan ("Savings Plan") that is available to virtually all employees. The Company provided matching contributions of 100% of the first 5% of the participant's compensation paid into the Savings Plan. Company contributions to the Savings Plan during the year ended December 31, 2014, the year ended December 2013, the period from Acquisition (March 26, 2012) to December 31, 2012 and the period from January 1, 2012 to March 25, 2012 were $3 million, $6 million, $4 million and $2 million, respectively.

In addition, the Company provides a 3% discretionary profit sharing contribution to eligible employees with annual base compensation below a specific threshold. Company contributions are 100% vested after five years of continuous service. The Company's fixed contributions during the year ended December 31, 2014, the year ended December 31, 2013, the period from Acquisition (March 26, 2012) to December 31, 2012 and the period from January 1, 2012 to March 25, 2012 were $2 million, $3 million, $2 million and $2 million, respectively.

9. INCOME TAXES:

The following table provides a summary of the current and deferred components of income tax expense (benefit) from continuing operations:

	Successor			Predecessor
	Year Ended December 31, 2014	Year Ended December 31, 2013	Period from Acquisition (March 26, 2012) to December 31, 2012	Period from January 1, 2012 to March 25, 2012
Current expense (benefit):				
Federal	$ 261	$ (52)	$ (43)	$ —
State	24	(7)	3	(1)
Total	285	(59)	(40)	(1)
Deferred expense (benefit):				
Federal	$ (114)	$ 119	$ 81	$ 10
State	(25)	38	(2)	3
Total	(139)	157	79	13
Total income tax expense	$ 146	$ 98	$ 39	$ 12

The differences between the Company's effective income tax rate and the U.S. federal income tax statutory rate were as follows:

	Successor			Predecessor
	Year Ended December 31, 2014	Year Ended December 31, 2013	Period from Acquisition (March 26, 2012) to December 31, 2012	Period from January 1, 2012 to March 25, 2012
Computed statutory income tax expense (benefit) at 35%	$ 50	$ (165)	$ 17	$ 16
Changes in income taxes resulting from:				
Earnings from unconsolidated investments related to anticipated receipt of dividends	—	—	5	(5)
Non-deductible executive compensation	—	—	18	—
Premium on debt retirement	(10)	—	—	—
State income taxes, net of federal income tax benefit	4	21	1	1
Non-deductible goodwill impairment	—	241	—	—
Non-deductible goodwill included in the Lake Charles LNG Transaction	105	—	—	—
Other	(3)	1	(2)	—
Income tax expense	$ 146	$ 98	$ 39	$ 12

Deferred income taxes result from temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The table below summarizes the principal components of the Company's deferred tax assets (liabilities) as follows:

	December 31,	
	2014	2013
Deferred income tax assets:		
Other postretirement benefits	$ 5	$ 5
Debt amortization	40	67
Other	26	40
Total deferred income tax assets	71	112
Valuation allowance	(2)	—
Net deferred income tax assets	$ 69	$ 112
Deferred income tax liabilities:		
Property, plant and equipment	$ (776)	$ (956)
Investment in unconsolidated affiliates	(795)	(793)
Other	(6)	(16)
Total deferred income tax liabilities	(1,577)	(1,765)
Net deferred income tax liability	(1,508)	(1,653)
Less current income tax assets	3	6
Accumulated deferred income taxes	$ (1,511)	$ (1,659)

As of December 31, 2014, the Company has $18 million ($12 million, net of federal tax) of unrecognized tax benefits, $11 million of which would impact the Company's effective income tax rate if recognized. The Company expects that its unrecognized tax benefits will be reduced by $2 million within the next 12 months.

The Company's policy is to classify and accrue interest expense and penalties on income tax underpayments (overpayments) as a component of income tax expense in its consolidated statement of operations, which is consistent with the recognition of these items in prior reporting periods.

The Company and Southern Union are no longer subject to U.S. federal, state or local examinations for the tax periods prior to 2005. The Company and Southern Union are under examination by the Internal Revenue Service (IRS) for the tax years 2004 through 2009. For the 2006 tax year, the IRS has challenged $545 million of the $690 million deferred gain associated with the like kind exchange involving certain assets of Southern Union's distribution operations and gathering and processing operations. The Company and Southern Union have been vigorously defending this tax position and believe it has reached a tentative settlement with the IRS which will not have a material impact on these financial statements.

10. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Interest Rate Contracts

The Company had no outstanding interest rate swap agreements as of December 31, 2014.

The Company previously used interest rate swap agreements to hedge floating rate notes with an aggregate notional amount. The Company settled $50 million of five-year swaps during the third quarter of 2013, $175 million of ten-year swaps during the fourth quarter of 2013, $25 million of five-year swaps during the fourth quarter of 2013, $150 million of ten-year swaps during the third quarter of 2014, and the remaining $125 million of ten-year swaps during the fourth quarter of 2014. The Company paid interest on the floating rate notes based on three-month LIBOR plus a credit spread of 3.0175%.

Credit Risk

Credit risk refers to the risk that a shipper may default on its contractual obligations resulting in a credit loss to the Company. A credit policy has been approved and implemented to govern the Company's portfolio of shippers with the objective of mitigating credit losses. This policy establishes guidelines, controls, and limits, consistent with FERC filed tariffs, to manage credit risk within approved tolerances by mandating an appropriate evaluation of the financial condition of existing and potential shippers, monitoring agency credit ratings, and by implementing credit practices that limit credit exposure according to the risk profiles of the shippers. Furthermore, the Company may, at times, require collateral under certain circumstances in order to mitigate credit risk as necessary.

The Company's shippers consist of a diverse portfolio of customers across the energy industry, including oil and gas producers, midstream companies, municipalities, utilities, and commercial and industrial end users. Our overall exposure may be affected positively or negatively by macroeconomic or regulatory changes that could impact our shippers to one extent or another. Currently, management does not anticipate a material adverse effect in our financial position or results of operations as a consequence of shipper non-performance.

Summary Financial Statement Information

The following table summarizes the fair value amounts of the Company's asset and liability derivative instruments and their location reported in the consolidated balance sheets:

	Fair Value			
	Asset Derivatives		Liability Derivatives	
Balance Sheet Location	December 31, 2014	December 31, 2013	December 31, 2014	December 31, 2013
Economic Hedges:				
Interest rate contracts:				
Price risk management liabilities	$ —	$ —	$ —	$ 10
Non-current price management liabilities	—	—	—	15
Total	$ —	$ —	$ —	$ 25

The following table summarizes the location and amount (excluding income tax effects) of derivative instrument gains and losses reported in the Company's consolidated financial statements:

	Successor			Predecessor
	Year Ended December 31, 2014	Year Ended December 31, 2013	Period from Acquisition (March 26, 2012) to December 31, 2012	Period from January 1, 2012 to March 25, 2012
Cash Flow Hedges:				
Interest rate contracts:				
Change in fair value – increase in accumulated other comprehensive income	$ —	$ —	$ —	$ 6
Reclassification of unrealized loss from accumulated other comprehensive income – increase of interest expense	—	—	—	8
Commodity contracts — Gathering and Processing:				
Change in fair value – increase (decrease) in accumulated other comprehensive income	—	(3)	(6)	5
Reclassification of unrealized gain from accumulated other comprehensive income	—	—	1	2
Economic Hedges:				
Interest rate contracts:				
Change in fair value — increase (decrease) in interest expense	(7)	29	12	—
Commodity contracts:				
Change in fair value — decrease in deferred natural gas purchases	—	(7)	(32)	(2)

11. FAIR VALUE MEASUREMENT:

The Company did not have any assets or liabilities that are measured at fair value on a recurring basis at December 31, 2014. The following table sets forth the Company's assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2013:

	Fair Value as of	Fair Value Measurements at December 31, 2013 Using Fair Value Hierarchy	
	December 31, 2013	Level 1	Level 2
Assets:			
Total	$ —	$ —	$ —
Liabilities:			
Interest rate swaps	$ 25	$ —	$ 25
Total	$ 25	$ —	$ 25

The Company's Level 2 instruments primarily included interest rate swap derivatives that were valued using pricing models based on an income approach that discounts future cash flows to a present value amount. The significant pricing model inputs for interest rate swaps included published rates for U.S. Dollar LIBOR interest rate swaps. The pricing models also adjusted for nonperformance risk associated with the counterparty or Company, as applicable, through the use of credit risk adjusted discount rates based on published default rates. During the periods ended December 31, 2014 and 2013, no transfers were made between any levels within the fair value hierarchy. The company had no outstanding interest rate swap agreements at December 31, 2014.

The fair value of the Lake Charles LNG reporting unit was classified as Level 3 of the fair value hierarchy due to the significance of unobservable inputs developed using company-specific information. We used the income approach to measure the fair value of the Lake Charles LNG reporting unit. Under the income approach, we calculated the fair value based on the present value of the estimated future cash flows. The discount rate used, which was an unobservable input, was based on the weighted-average cost of capital adjusted for the relevant risk associated with business-specific characteristics and the uncertainty related to the business's ability to attain the projected cash flows.

The approximate fair value of the Company's cash and cash equivalents, accounts receivable and accounts payable is equal to book value, due to their short-term nature.

12. PROPERTY, PLANT AND EQUIPMENT:

The following table provides a summary of property, plant and equipment:

		December 31,	
	Lives in Years	2014	2013
Land and improvements		$ 8	$ 8
Buildings and improvements	6 – 22	340	336
Pipelines and equipment	5 – 46	2,353	2,273
Natural gas storage facilities	5 – 46	323	314
Tanks and other equipment	20 – 40	—	955
Vehicles	5	23	23
Right of way	36 – 40	23	23
Furniture and fixtures	5 – 12	33	34
Linepack		57	57
Other	2 – 19	192	185
Construction work in progress		43	70
Total property, plant and equipment		3,395	4,278
Accumulated depreciation and amortization		(269)	(216)
Net property, plant and equipment		$ 3,126	$ 4,062

13. ASSET RETIREMENT OBLIGATIONS:

The Company's recorded asset retirement obligations are primarily related to owned natural gas storage wells and offshore lines and platforms. At the end of the useful life of these underlying assets, the Company is legally or contractually required to abandon in place or remove the asset. An ARO is required to be recorded when a legal obligation to retire an asset exists and such obligation can be reasonably estimated. Although a number of other onshore assets in the Company's system are subject to agreements or regulations that give rise to an ARO upon the Company's discontinued use of these assets, AROs were not recorded because these assets have an indeterminate removal or abandonment date given the expected continued use of the assets with proper maintenance or replacement.

Individual component assets have been and will continue to be replaced, but the pipeline system will continue in operation as long as supply and demand for natural gas exists. Based on the widespread use of natural gas in industrial and power generation activities, management expects supply and demand to exist for the foreseeable future. The Company has in place a rigorous repair and maintenance program that keeps the pipeline system in good working order. Therefore, although some of the individual assets may be replaced, the pipeline system itself will remain intact indefinitely.

The Company had recorded AROs related to (i) retiring natural gas storage wells, (ii) retiring offshore platforms and lines and (iii) removing asbestos. Amounts reflected in long-lived assets related to AROs aggregated approximately $18 million and $13 million and were reflected as other non-current assets on our balance sheet as of December 31, 2014 and 2013, respectively.

As of December 31, 2014, the Company had no material legally restricted funds for the purpose of settling AROs.

The following table is a reconciliation of the carrying amount of the ARO liability reflected as liabilities on our balance sheet for the periods presented. Changes in assumptions regarding the timing, amount, and probabilities associated with the expected cash flows, as well as the difference in actual versus estimated costs, will result in a change in the amount of the liability recognized.

	Successor			Predecessor
	Year Ended December 31, 2014	Year Ended December 31, 2013	Period from Acquisition (March 26, 2012) to December 31, 2012	Period from January 1, 2012 to March 25, 2012
Beginning balance	$ 55	$ 46	$ 46	$ 46
Revisions	3	11	3	—
Settled	(3)	(1)	(5)	—
Disposals	—	(4)	—	—
Accretion expense	3	3	2	—
Ending balance	$ 58	$ 55	$ 46	$ 46

During 2013, the Company recorded an $11 million upward revision to its prior ARO liability estimates, primarily due to changes in ARO liabilities as a result of a third party evaluation. Also in 2013, the Company disposed of $4 million in ARO liabilities in the SUGS Contribution.

14. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES:

Trunkline Transfer Applications

In October 2011, Trunkline and Sea Robin jointly filed with FERC to transfer all of Trunkline's offshore facilities, and certain related onshore facilities, by sale and transfer to Sea Robin to consolidate and streamline the ownership and operation of all regulated offshore assets under one entity and better position the offshore assets competitively. Several parties filed interventions and protests of this filing. On June 21, 2012, FERC issued an order granting Trunkline permission and approval to proceed with the transfer, subject to compliance with certain regulatory requirements. On July 31, 2012 Sea Robin and Trunkline made the necessary compliance filings with FERC. The transfer of the offshore facilities to Sea Robin was effective September 1, 2012.

On July 26, 2012, Trunkline filed an application with the FERC for approval to transfer approximately 770 miles of underutilized loop piping facilities by sale to an affiliate, and such facilities are contemplated to be converted to crude oil transportation service. This sale was approved by the FERC on November 7, 2013.

Sea Robin Rate Case

On December 2, 2013, Sea Robin filed a general NGA Section 4 rate case at the FERC as required by a previous rate case settlement. In the filing, Sea Robin seeks to increase its authorized rates to recover costs related to asset retirement obligations, depreciation, and return and taxes. Filed rates were put into effect June 1, 2014 and estimated settlement rates were put into effect September 1, 2014, subject of refund. A settlement was reached with the shippers and a stipulation and agreement was filed with the FERC on July 23, 2014. The settlement was certified to the FERC by the administrative law judge on October 7, 2014 and was conditionally approved by the FERC on December 18, 2014.

PEPL Holdings Guarantee of Collection

In connection with the SUGS Contribution, Regency issued $600 million of 4.50% Senior Notes due 2023 (the "Regency Debt"), the proceeds of which were used by Regency to fund the cash portion of the consideration, as adjusted, and pay certain other expenses or disbursements directly related to the closing of the SUGS Contribution. Pursuant to an agreement between Regency and PEPL Holdings, PEPL Holdings provided a guarantee of collection (on a nonrecourse basis to Southern Union) to Regency and Regency Energy Finance Corp. with respect to the payment of the principal amount of the Regency Debt through maturity in 2023. In connection with the completion of the Panhandle Merger, in which PEPL Holdings was merged with and into Panhandle, the guarantee of collection for the Regency Debt was assumed by Panhandle.

Contingent Residual Support Agreement with ETP

In connection with the Panhandle Merger, the Company assumed Southern Union's obligations under a contingent residual support agreement with ETP and Citrus ETP Finance LLC, pursuant to which the Company provides contingent, residual support to Citrus ETP Finance LLC (on a non-recourse basis to the Company) with respect to Citrus ETP Finance LLC's obligations to ETP to support the payment of $2.0 billion in principal amount of senior notes issued by ETP on January 17, 2012.

Environmental Matters

The Company's operations are subject to federal, state and local laws, rules and regulations regarding water quality, hazardous and solid waste management, air quality control and other environmental matters. These laws, rules and regulations require the Company to conduct its operations in a specified manner and to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with environmental laws, rules and regulations may expose the Company to significant fines, penalties and/or interruptions in operations. The Company's environmental policies and procedures are designed to achieve compliance with such applicable laws and regulations. These evolving laws and regulations and claims for damages to property, employees, other persons and the environment resulting from current or past operations may result in significant expenditures and liabilities in the future. The Company engages in a process of updating and revising its procedures for the ongoing evaluation of its operations to identify potential environmental exposures and enhance compliance with regulatory requirements.

Environmental Remediation

The Company is responsible for environmental remediation at certain sites on its natural gas transmission systems for contamination resulting from the past use of lubricants containing PCBs in compressed air systems; the past use of paints containing PCBs; and the prior use of wastewater collection facilities and other on-site disposal areas. The Company has implemented a program to remediate such contamination. The primary remaining remediation activity on the Panhandle systems is associated with past use of paints containing PCBs or PCB impacts to equipment surfaces and to a building at one location. The PCB assessments are ongoing and the related estimated remediation costs are subject to further change. Other remediation typically involves the management of contaminated soils and may involve remediation of groundwater. Activities vary with site conditions and locations, the extent and nature of the contamination, remedial requirements, complexity and sharing of responsibility. The ultimate liability and total costs associated with these sites will depend upon many factors. If remediation activities involve statutory joint and several liability provisions, strict liability, or cost recovery or contribution actions, the Company could potentially be held responsible for contamination caused by other parties. In some instances, the Company may share liability associated with contamination with other potentially related parties. The Company may also benefit from contractual indemnities that cover some or all of the cleanup costs. These sites are generally managed in the normal course of business or operations.

Our pipeline operations are subject to regulation by the U.S. Department of Transportation under the PHMSA, pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as "high consequence areas." Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur future capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines; however, no estimate can be made at this time of the likely range of such expenditures.

The Company's environmental remediation activities are undertaken in cooperation with and under the oversight of appropriate regulatory agencies, enabling the Company under certain circumstances to take advantage of various voluntary cleanup programs in order to perform the remediation in the most effective and efficient manner.

Environmental Remediation Liabilities

The table below reflects the amount of accrued liabilities recorded in the consolidated balance sheets at the dates indicated to cover environmental remediation actions where management believes a loss is probable and reasonably estimable. The Company is not able to estimate the possible loss or range of loss in excess of amounts accrued. The Company does not have any material environmental remediation matters assessed as reasonably possible.

	December 31,	
	2014	2013
Current	$ 1	$ 2
Non-current	3	3
Total environmental liabilities	$ 4	$ 5

Litigation and Other Claims

The Company is involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business.

Attorney General of the Commonwealth of Massachusetts v New England Gas Company. On July 7, 2011, the Massachusetts Attorney General ("AG") filed a regulatory complaint with the Massachusetts Department of Public Utilities ("MDPU") against New England Gas Company with respect to certain environmental cost recoveries. The AG is seeking a refund to New England Gas Company customers for alleged "excessive and imprudently incurred costs" related to legal fees associated with Southern Union's environmental response activities. In the complaint, the AG requests that the MDPU initiate an investigation into the New England Gas Company's collection and reconciliation of recoverable environmental costs including: (i) the prudence of any and all legal fees, totaling $19 million, that were charged by the Kasowitz, Benson, Torres & Friedman firm and passed through the recovery mechanism since 2005, the year when a partner in the firm, Southern Union's former Vice Chairman, President and Chief Operating Officer, joined Southern Union's management team; (ii) the prudence of any and all legal fees that were charged by the Bishop, London & Dodds firm and passed through the recovery mechanism since 2005, the period during which a member of the firm served as Southern Union's Chief Ethics Officer; and (iii) the propriety and allocation of certain legal fees charged that were passed through the recovery mechanism that the AG contends only qualify for a lesser, 50%, level of recovery. Southern Union has filed its answer denying the allegations and moved to dismiss the complaint, in part on a theory of collateral estoppel. The hearing officer has deferred consideration of Southern Union's motion to dismiss. The AG's motion to be reimbursed expert and consultant costs by Southern Union of up to $150,000 was granted. By tariff, these costs are recoverable through rates charged to New England Gas Company customers. The hearing officer previously stayed discovery pending resolution of a dispute concerning the applicability of attorney-client privilege to legal billing invoices. The MDPU issued an interlocutory order on June 24, 2013 that lifted the stay, and discovery has resumed. The Company (as successor to Southern Union) believes it has complied with all applicable requirements regarding its filings for cost recovery and has not recorded any accrued liability; however, the Company will continue to assess its potential exposure for such cost recoveries as the matter progresses.

Liabilities for Litigation and Other Claims

The Company records accrued liabilities for litigation and other claim costs when management believes a loss is probable and reasonably estimable. When management believes there is at least a reasonable possibility that a material loss or an additional material loss may have been incurred, the Company discloses (i) an estimate of the possible loss or range of loss in excess of the amount accrued; or (ii) a statement that such an estimate cannot be made. As of December 31, 2014 and 2013, the Company recorded litigation and other claim-related accrued liabilities of $21 million and $24 million, respectively. The Company does not have any material litigation or other claim contingency matters assessed as probable or reasonably possible that would require disclosure in the financial statements.

Other Commitments and Contingencies

Unclaimed Property Audits. The Company is subject to the laws and regulations of states and other jurisdictions concerning the identification, reporting and escheatment (the transfer of property to the state) of unclaimed or abandoned funds, and is subject to audit and examination for compliance with these requirements. The Company is currently being examined by a third party auditor on behalf of nine states for compliance with unclaimed property laws.

15. QUARTERLY FINANCIAL DATA (UNAUDITED):

The following table provides certain quarterly financial information for the periods presented:

	Quarters Ended				
	March 31, 2014	June 30, 2014	September 30, 2014	December 31, 2014	Total
Operating revenues	$ 178	$ 128	$ 132	$ 143	$ 581
Operating income	90	34	31	38	193
Net income (loss)	(35)	16	23	(7)	(3)
Net income (loss) attributable to partners	(41)	16	23	(7)	(9)

	March 31, 2013	June 30, 2013	September 30, 2013	December 31, 2013	Total
Operating revenues	$ 393	$ 316	$ 182	$ 194	$ 1,085
Operating income (loss)	55	115	67	(619)	(382)
Net income (loss)	36	40	58	(669)	(535)
Net income (loss) attributable to partners	42	69	37	(647)	(499)

Exhibit 12.1

Panhandle Eastern Pipe Line Company, LP

Computation of Ratio of Earnings to Fixed Charges

(in millions, except for ratio amounts)

(Unaudited)

The following table sets forth the consolidated ratio of earnings to fixed charges on an historical basis for the years ended December 31, 2014 and 2013, the periods from March 26, 2012 to December 31, 2012 and January 1, 2012 to March 25, 2012 and the years ended December 31, 2011 and 2010. For the purpose of calculating such ratios, "earnings" consist of pre-tax income from continuing operations before income or loss from equity investees, adjusted to reflect distributed income from equity investments, and fixed charges, less capitalized interest. "Fixed charges" consist of interest costs, amortization of debt discount, premiums and issuance costs and an estimate of interest implicit in rentals. No adjustment has been made to earnings for the amortization of capital interest for the periods presented as such amount is immaterial.

On January 10, 2014, the Company consummated a merger with Southern Union, the indirect parent of the Company, and PEPL Holdings, the sole limited partner of the Company, pursuant to which each of Southern Union and PEPL Holdings, a wholly-owned subsidiary of Southern Union, were merged with and into the Company (the "Panhandle Merger"), with the Company surviving the Panhandle Merger. We have accounted for this transaction as a reorganization of entities under common control; therefore, the consolidated financial statements of the Company were retrospectively adjusted to consolidate Southern Union for all periods.

	Successor			Predecessor		
	Years Ended December 31,		Period from Acquisition (March 26, 2012) to December 31, 2012	Period from January 1, 2012 to March 25, 2012	Years Ended December 31,	
	2014	2013			2011	2010
Fixed Charges:						
Interest expense, net	$ 66	$ 111	$ 131	$ 50	$ 217	$ 210
Net amortization of debt discount, premium and issuance expense	(22)	(28)	(24)	2	6	7
Capitalized interest	2	1	1	—	1	7
Interest charges included in rental expense	1	2	5	2	7	6
Total fixed charges	$ 47	$ 86	$ 113	$ 54	$ 231	$ 230
Earnings:						
Income (loss) from continuing operations before income tax expense and noncontrolling interest	$ 143	$ (472)	$ 50	$ 45	$ 294	$ 278
Less: equity in earnings (losses) of unconsolidated affiliates	(12)	15	(7)	16	99	105
Total earnings	155	(487)	57	29	195	173
Add:						
Fixed Charges	47	86	113	54	231	230
Distributed income of equity investees	72	54	6	—	3	4
Less:						
Interest capitalized	(2)	(1)	(1)	—	(1)	(7)
Income Available for Fixed Charges	$ 272	$ (348)	$ 175	$ 83	$ 428	$ 400
Ratio of earnings to fixed charges	5.79	(a)	1.55	1.54	1.85	1.74

(a) For the year ended December 31, 2013, fixed charges exceeded earnings by $434 million. In 2013, Panhandle Eastern Pipe Line Company, LP recognized a $689 million goodwill impairment charge associated with the Lake Charles LNG reporting unit.

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Kelcy L. Warren, certify that:

1. I have reviewed this annual report on Form 10-K of Panhandle Eastern Pipe Line Company, LP (the “registrant”);

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

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

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

Date: February 26, 2015

/s/ Kelcy L. Warren

Kelcy L. Warren
Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Martin Salinas, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Panhandle Eastern Pipe Line Company, LP (the “registrant”);

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

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

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

Date: February 26, 2015

/s/ Martin Salinas, Jr.

Martin Salinas, Jr.
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 Panhandle Eastern Pipe Line Company, LP (the "Company") on Form 10-K for the year ended December 31, 2014 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Kelcy L. Warren, 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, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

Date: February 26, 2015

/s/ Kelcy L. Warren
Kelcy L. Warren
Chief Executive Officer

*A signed original of this written statement required by 18 U.S.C. Section 1350 has been provided to and will be retained by Panhandle Eastern Pipe Line Company, LP.

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 Panhandle Eastern Pipe Line Company, LP (the “Company”) on Form 10-K for the year ended December 31, 2014 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Martin Salinas, Jr., 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, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

Date: February 26, 2015

/s/ Martin Salinas, Jr.
Martin Salinas, Jr.
Chief Financial Officer

*A signed original of this written statement required by 18 U.S.C. Section 1350 has been provided to and will be retained by Panhandle Eastern Pipe Line Company, LP.

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Introductory Statement

References in this report to the “Partnership,” “we,” “our,” “us” and similar terms refer to Regency Energy Partners LP and its subsidiaries. We use the following definitions in these consolidated financial statements and footnotes:

Name	Definition or Description
2018 Notes	$600 million of 6.875% senior notes with original maturity on December 1, 2018
AOCI	Accumulated Other Comprehensive Income (Loss)
Aqua - PVR	Aqua - PVR Water Services, LLC
ARO	Asset Retirement Obligation
APM	Anadarko Pecos Midstream LLC
Barclays	Barclays Capital Inc.
bps	Basis points
Citi	Citigroup Global Markets Inc.
CM	Chesapeake West Texas Processing, L.L.C.
Coal Handling	Coal Handling Solutions LLC, Kingsport Handling LLC, and Kingsport Services LLC, now known as Materials Handling Solutions LLC
Eagle Rock	Eagle Rock Energy Partners, L.P.
EFS Haynesville	EFS Haynesville, LLC, a wholly-owned subsidiary of GECC
ELG	Edwards Lime Gathering LLC and its wholly-owned subsidiaries, ELG Oil LLC and ELG Utility LLC
EPD	Enterprise Products Partners L.P.
ETC	Energy Transfer Company, the name assumed by La Grange Acquisition, L.P. for conducting business and shared services, a wholly-owned subsidiary of ETP
ETE	Energy Transfer Equity, L.P.
ETE Common Holdings	ETE Common Holdings, LLC, a wholly-owned subsidiary of ETE
ETE GP	ETE GP Acquirer LLC
ETP	Energy Transfer Partners, L.P.
ETP GP	Energy Transfer Partners GP, LP
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FASB ASC	FASB Accounting Standards Codification
Finance Corp.	Regency Energy Finance Corp., a wholly-owned subsidiary of the Partnership
GAAP	Accounting principles generally accepted in the United States of America
General Partner	Regency GP LP, the general partner of the Partnership, or Regency GP LLC, the general partner of Regency GP LP, which effectively manages the business and affairs of the Partnership through its board of directors and Regency Employees Management LLC
Grey Ranch	Grey Ranch Plant LP, a former joint venture of the Partnership
Gulf States	Gulf States Transmission LLC, a wholly-owned subsidiary of the Partnership
Holdco	ETP Holdco Corporation
Hoover	Hoover Energy Partners, LP
HPC	RIGS Haynesville Partnership Co. and its wholly-owned subsidiary, Regency Intrastate Gas LP
IDRs	Incentive Distribution Rights
IRS	Internal Revenue Service
KMP	Kinder Morgan Energy Partners, L.P.
LDH	LDH Energy Asset Holdings LLC
LIBOR	London Interbank Offered Rate
Lone Star	Lone Star NGL LLC
LTIP	Long-Term Incentive Plan

Name	Definition or Description
MEP	Midcontinent Express Pipeline LLC
Mi Vida JV	Mi Vida JV LLC
MLP	Master Limited Partnership
NGLs	Natural gas liquids, including ethane, propane, normal butane, iso butane and natural gasoline
NMED	New Mexico Environmental Development
NYSE	New York Stock Exchange
ORS	Ohio River System LLC
PADEP	Pennsylvania Department of Environmental Protection
Partnership	Regency Energy Partners LP
PEPL	Panhandle Eastern Pipe Line Company, LP
PEPL Holdings	PEPL Holdings, LLC, a former wholly-owned subsidiary of Southern Union that merged into PEPL
PVR	PVR Partners, L.P.
Ranch JV	Ranch Westex JV LLC
Regency Western	Regency Western G&P LLC, a wholly-owned subsidiary of the Partnership
RGS	Regency Gas Services, LP, a wholly-owned subsidiary of the Partnership
RIGS	Regency Intrastate Gas System
SEC	Securities and Exchange Commission
Securities Act	Securities Act of 1933, as amended
Senior Notes	The collective of 2019 Notes, 2020 Notes, 2020 PVR Notes, 2021 Notes, 2021 PVR Notes, 2022 Notes, October 2022 Notes, 2023 4.5% Notes and 2023 5.5% Notes
Series A Preferred Units	Series A convertible redeemable preferred units
Services Co.	ETE Services Company, LLC
Southern Union	Southern Union Company
SUGS	Southern Union Gas Services
SUN	Sunoco LP (formerly known as Susser, L.P.)
Sweeny JV	Sweeny Gathering, L.P.
SXL	Sunoco Logistics Partners L.P.
TCEQ	Texas Commission on Environmental Quality
U.S.	United States
Wells Fargo	Wells Fargo Securities, LLC
WTI	West Texas Intermediate Crude

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Regency Energy Partners LP

We have audited the accompanying consolidated balance sheets of Regency Energy Partners LP (a Delaware limited partnership) and subsidiaries (the "Partnership") as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, cash flows, and partners' capital and noncontrolling interest for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits. We did not audit the financial statements of Midcontinent Express Pipeline LLC, a 50 percent owned investee company, the Partnership's investment in which is accounted for under the equity method of accounting. The Partnership's investment in Midcontinent Express Pipeline LLC as of December 31, 2014 and 2013 was $695 million and $549 million, respectively, and its equity in the earnings of Midcontinent Express Pipeline LLC was $45 million, $40 million, and $42 million, respectively, for each of the three years in the period ended December 31, 2014. Those statements were audited by other auditors, whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Midcontinent Express Pipeline LLC, is based solely on the report of the other auditors.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the report of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Regency Energy Partners LP and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership's internal control over financial reporting as of December 31, 2014, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 26, 2015 (not separately included herein) expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 26, 2015

REGENCY ENERGY PARTNERS LP

CONSOLIDATED BALANCE SHEETS

(Dollars in millions)

	December 31,	
	2014	**2013**
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 24	$ 19
Trade accounts receivable, net of allowance for doubtful accounts of $7 and $1	483	292
Related party receivables	45	28
Inventories	67	42
Derivative assets	75	3
Other current assets	9	16
Total current assets	703	400
Property, Plant and Equipment:		
Gathering and transmission systems	5,207	1,671
Compression equipment	2,378	1,627
Gas plants and buildings	386	825
Other property, plant and equipment	679	414
Natural resources	454	—
Construction-in-progress	1,156	513
Total property, plant and equipment	10,260	5,050
Less accumulated depreciation and depletion	(1,043)	(632)
Property, plant and equipment, net	9,217	4,418
Other Assets:		
Investments in unconsolidated affiliates	2,418	2,097
Other, net of accumulated amortization of debt issuance costs of $28 and $24	103	57
Total other assets	2,521	2,154
Intangible Assets and Goodwill:		
Intangible assets, net of accumulated amortization of $212 and $107	3,439	682
Goodwill	1,223	1,128
Total intangible assets and goodwill	4,662	1,810
TOTAL ASSETS	$ 17,103	$ 8,782

The accompanying notes are an integral part of these consolidated financial statements.

REGENCY ENERGY PARTNERS LP
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	December 31,	
	2014	2013
LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Drafts payable	$ 15	$ 26
Trade accounts payable	529	291
Related party payables	64	69
Accrued expenses	43	25
Accrued interest	81	38
Other current liabilities	24	26
Total current liabilities	756	475
Long-term derivative liabilities	16	19
Other long-term liabilities	72	30
Long-term debt, net	6,641	3,310
Commitments and contingencies		
Series A Preferred Units, redemption amount of $38 and $38	33	32
Partners' Capital and Noncontrolling Interest:		
Common units (412,681,151 and 214,287,955 units authorized; 409,406,482 and 210,850,232 units issued and outstanding at December 31, 2014 and 2013)	8,531	3,886
Class F units (6,274,483 units authorized, issued and outstanding at December 31, 2014 and 2013)	153	146
General partner interest	781	782
Total partners' capital	9,465	4,814
Noncontrolling interest	120	102
Total partners' capital and noncontrolling interest	9,585	4,916
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$ 17,103	$ 8,782

The accompanying notes are an integral part of these consolidated financial statements.

REGENCY ENERGY PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in millions, except unit data and per unit data)

	Years Ended December 31, 2014	2013	2012
REVENUES			
Gas sales, including related party amounts of $80, $71, and $42	$ 1,903	$ 826	$ 508
NGL sales, including related party amounts of $282, $81, and $28	1,741	1,053	991
Gathering, transportation and other fees, including related party amounts of $23, $26, and $29	989	545	401
Net realized and unrealized gain (loss) from derivatives	93	(8)	23
Other	225	105	77
Total revenues	4,951	2,521	2,000
OPERATING COSTS AND EXPENSES			
Cost of sales, including related party amounts of $66, $56, and $35	3,452	1,793	1,387
Operation and maintenance	448	296	228
General and administrative	158	88	100
(Gain) loss on asset sales, net	(1)	2	3
Depreciation, depletion and amortization	541	287	252
Goodwill impairment	370	—	—
Total operating costs and expenses	4,968	2,466	1,970
OPERATING (LOSS) INCOME	(17)	55	30
Income from unconsolidated affiliates	195	135	105
Interest expense, net	(304)	(164)	(122)
Loss on debt refinancing, net	(25)	(7)	(8)
Other income and deductions, net	12	7	29
(LOSS) INCOME BEFORE INCOME TAXES	(139)	26	34
Income tax expense (benefit)	3	(1)	—
NET (LOSS) INCOME	$ (142)	$ 27	$ 34
Net income attributable to noncontrolling interest	(15)	(8)	(2)
NET (LOSS) INCOME ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$ (157)	$ 19	$ 32
Amounts attributable to Series A preferred units	4	6	10
General partner's interest, including IDRs	31	11	9
Beneficial conversion feature for Class F units	7	4	—
Pre-acquisition loss from SUGS allocated to predecessor equity	—	(36)	(14)
Limited partners' interest in net (loss) income	$ (199)	$ 34	$ 27
Basic and diluted (loss) income per common unit:			
Limited partners' interest in net (loss) income	$ (199)	$ 34	$ 27
Weighted average number of common units outstanding	348,070,121	196,227,348	167,492,735
Basic (loss) income per common unit	$ (0.57)	$ 0.17	$ 0.16
Diluted (loss) income per common unit	$ (0.57)	$ 0.17	$ 0.13
Distributions per common unit	$ 1.975	$ 1.87	$ 1.84
Amount allocated to beneficial conversion feature for Class F units	$ 7	$ 4	$ —
Total number of Class F units outstanding	6,274,483	6,274,483	—
Income per Class F unit due to beneficial conversion feature	$ 1.08	$ 0.72	$ —

The accompanying notes are an integral part of these consolidated financial statements.

REGENCY ENERGY PARTNERS LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME
(Dollars in millions)

	Years Ended December 31,		
	2014	2013	2012
Net (loss) income	$ (142)	$ 27	$ 34
Other comprehensive income:			
Net cash flow hedge amounts reclassified to earnings	—	—	6
Change in fair value of cash flow hedges	—	—	(4)
Total other comprehensive income	$ —	$ —	$ 2
Comprehensive (loss) income	$ (142)	$ 27	$ 36
Comprehensive income attributable to noncontrolling interest	15	8	2
Comprehensive (loss) income attributable to Regency Energy Partners LP	$ (157)	$ 19	$ 34

The accompanying notes are an integral part of these consolidated financial statements.

REGENCY ENERGY PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in millions)

	Years Ended December 31,		
	2014	2013	2012
OPERATING ACTIVITIES			
Net (loss) income	$ (142)	$ 27	$ 34
Reconciliation of net (loss) income to net cash flows provided by operating activities:			
Depreciation, depletion and amortization, including debt issuance cost amortization and bond premium write-off and amortization	525	293	259
Income from unconsolidated affiliates	(195)	(135)	(105)
Derivative valuation changes	(93)	6	(12)
(Gain) loss on asset sales, net	(1)	2	3
Unit-based compensation expenses	10	7	5
Revaluation of unconsolidated affiliate upon acquisition	(6)	—	—
Goodwill impairment	370	—	—
Cash flow changes in current assets and liabilities:			
Trade accounts receivable and related party receivables	28	(96)	—
Other current assets and other current liabilities	34	(54)	10
Trade accounts payable and related party payables	(16)	119	18
Distributions of earnings received from unconsolidated affiliates	204	142	121
Cash flow changes in other assets and liabilities	1	125	(9)
Net cash flows provided by operating activities	719	436	324
INVESTING ACTIVITIES			
Capital expenditures	(1,088)	(1,034)	(560)
Contributions to unconsolidated affiliates	(355)	(148)	(356)
Distributions in excess of earnings of unconsolidated affiliates	68	249	83
Acquisitions, net of cash received	(805)	(475)	—
Proceeds from asset sales	11	15	26
Net cash flows used in investing activities	(2,169)	(1,393)	(807)
FINANCING ACTIVITIES			
Borrowings (repayments) under revolving credit facility, net	380	318	(140)
Proceeds from issuance of senior notes	1,580	1,000	700
Redemptions of senior notes	(983)	(163)	(88)
Debt issuance costs	(31)	(24)	(15)
Partner distributions and distributions on unvested unit awards	(706)	(386)	(322)
Noncontrolling interest contributions, net of distributions	3	17	42
Contributions from previous parent	—	—	51
Drafts payable	(11)	18	4
Common units issued under unit offerings, equity distribution program and LTIP, net of issuance costs, forfeitures and tax withholding	1,227	149	311
Distributions to Series A Preferred Units	(4)	(6)	(8)
Net cash flows provided by financing activities	1,455	923	535

The accompanying notes are an integral part of these consolidated financial statements.

REGENCY ENERGY PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in millions)

	Years Ended December 31,		
	2014	2013	2012
Net change in cash and cash equivalents	5	(34)	52
Cash and cash equivalents at beginning of period	19	53	1
Cash and cash equivalents at end of period	$ 24	$ 19	$ 53
Supplemental cash flow information:			
Accrued capital expenditures	$ 102	$ 60	$ 136
Issuance of Class F and common units in connection with SUGS Acquisition	—	961	—
Issuance of common units in connection with PVR, Hoover, and Eagle Rock acquisitions	4,281	—	—
Long-term debt assumed in PVR Acquisition	1,887	—	—
Long-term debt exchanged in connection with the Eagle Rock Midstream Acquisition	499	—	—
Interest paid, net of amounts capitalized	303	146	112
Accrued capital contribution to unconsolidated affiliate	—	13	23

The accompanying notes are an integral part of these consolidated financial statements.

REGENCY ENERGY PARTNERS LP
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
AND NONCONTROLLING INTEREST
(Dollars in millions)

	Regency Energy Partners LP						
	Common Units	Class F Units	General Partner Interest	Predecessor Equity	AOCI	Non-controlling Interest	Total
Balance - December 31, 2011	$ 3,173	$ —	$ 330	$ —	$ (5)	$ 33	$ 3,531
Common unit offerings, net of costs	297	—	—	—	—	—	297
Issuance of common units under equity distribution program, net of costs	15	—	—	—	—	—	15
Common units issued under LTIP, net of forfeitures and tax withholding	(1)	—	—	—	—	—	(1)
Unit-based compensation expenses	5	—	—	—	—	—	5
Partner distributions	(309)	—	(13)	—	—	—	(322)
Net income (loss)	37	—	9	(14)	—	2	34
Noncontrolling interest contributions, net of distributions	—	—	—	—	—	42	42
Distributions to Series A Preferred Units	(8)	—	—	—	—	—	(8)
Accretion of Series A Preferred Units	(2)	—	—	—	—	—	(2)
Net cash flow hedge amounts reclassified to earnings	—	—	—	—	5	—	5
Contribution of net investment to unitholders	—	—	—	1,747	(3)	—	1,744
Balance - December 31, 2012	$ 3,207	$ —	$ 326	$ 1,733	$ (3)	$ 77	$ 5,340
Contribution of net investment to the Partnership	—	—	1,925	(1,928)	3	—	—
Issuance of common units in connection with the SUGS Acquisition, net of costs	819	—	(819)	—	—	—	—
Issuance of Class F units in connection with the SUGS Acquisition, net of costs	—	142	(142)	—	—	—	—
Contribution of assets between entities under common control below historical cost	—	—	(504)	231	—	—	(273)
Issuance of common units under equity distribution program, net of costs	149	—	—	—	—	—	149
Conversion of Series A Preferred Units for common units	41	—	—	—	—	—	41
Unit-based compensation expenses	7	—	—	—	—	—	7
Partner distributions and distributions on unvested unit awards	(371)	—	(15)	—	—	—	(386)
Noncontrolling interest contributions, net of distributions	—	—	—	—	—	17	17
Net income (loss)	40	4	11	(36)	—	8	27
Distributions to Series A Preferred Units	(6)	—	—	—	—	—	(6)
Balance - December 31, 2013	$ 3,886	$ 146	$ 782	$ —	$ —	$ 102	$ 4,916

The accompanying notes are an integral part of these consolidated financial statements.

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REGENCY ENERGY PARTNERS LP
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
AND NONCONTROLLING INTEREST
(Dollars in millions)

	Regency Energy Partners LP				
	Common Units	Class F Units	General Partner Interest	Noncontrolling Interest	Total
Balance - December 31, 2013	$ 3,886	$ 146	$ 782	$ 102	$ 4,916
Issuance of common units under equity distribution program, net of costs	428	—	—	—	428
Issuance of common units to ETE Common Holdings	800	—	—	—	800
Issuance of common units in connection with Hoover Acquisition	109	—	—	—	109
Issuance of common units in connection with PVR Acquisition	3,906	—	—	—	3,906
Issuance of common units in connection with Eagle Rock Midstream Acquisition	266	—	—	—	266
Common units issued under LTIP, net of forfeitures and tax withholding	(1)	—	—	—	(1)
Unit-based compensation expenses	10	—	—	—	10
Partner distributions and distributions on unvested unit awards	(674)	—	(32)	—	(706)
Noncontrolling interest contributions, net of distributions	—	—	—	3	3
Net (loss) income	(195)	7	31	15	(142)
Distributions to Series A Preferred Units	(4)	—	—	—	(4)
Balance - December 31, 2014	$ 8,531	$ 153	$ 781	$ 120	$ 9,585

The accompanying notes are an integral part of these consolidated financial statements.

REGENCY ENERGY PARTNERS LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Tabular dollar amounts, except unit and per unit data, are in millions)

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization. The consolidated financial statements presented herein contain the results of Regency Energy Partners LP and its subsidiaries (the "Partnership"), a Delaware limited partnership. The Partnership was formed on September 8, 2005, and completed its IPO on February 3, 2006. The Partnership and its subsidiaries are engaged in the business of gathering and processing, compression, treating and transportation of natural gas; the transportation, fractionation and storage of NGLs; the gathering, transportation and terminaling of oil (crude and/or condensate, a lighter oil) received from producers; natural gas and NGL marketing and trading; and the management of coal and natural resource properties in the United States. Regency GP LP is the Partnership's general partner and Regency GP LLC (collectively the "General Partner") is the managing general partner of the Partnership and the general partner of Regency GP LP.

Pending Merger with ETP. On January 25, 2015, the Partnership and ETP entered into the Merger Agreement pursuant to which the Partnership will merge with a wholly-owned subsidiary of ETP, with the Partnership continuing as the surviving entity and becoming a wholly-owned subsidiary of ETP (the "Merger"). At the effective time of the Merger (the "Effective Time"), each Partnership common unit and Class F unit will be converted into the right to receive 0.4066 ETP common units, plus a number of additional ETP common units equal to $0.32 per Partnership unit divided by the lesser of (i) the volume weighted average price of ETP common units for the five trading days ending on the third trading day immediately preceding the Effective Time and (ii) the closing price of ETP common units on the third trading day immediately preceding the Effective Time, rounded to the nearest ten thousandth of a unit. Each Series A Preferred Unit will be converted into the right to receive a preferred unit representing a limited partner interest in ETP, a new class of units in ETP to be established at the Effective Time. Early termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, for the Merger was granted by the United States Federal Trade Commission on February 24, 2015. The transaction is expected to close in the second quarter of 2015 and is subject to other customary closing conditions including approval by the Partnership's unitholders.

Basis of presentation. The consolidated financial statements of the Partnership have been prepared in accordance with GAAP and include the accounts of all controlled subsidiaries after the elimination of all intercompany accounts and transactions. Certain prior year numbers have been conformed to the current year presentation.

Reclassifications. During 2014, the Partnership reclassified amounts within property, plant and equipment asset categories. These reclassifications did not have any impact on amounts recorded for depreciation, depletion or amortization in 2014, and because the reclassified amounts have no significant effect on our consolidated balance sheets, prior period balances have not been adjusted for comparability purposes.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates. These consolidated financial statements have been prepared in conformity with GAAP, which includes the use of estimates and assumptions by management that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities that exist at the date of the financial statements. Although these estimates are based on management's available knowledge of current and expected future events, actual results could be different from those estimates.

Common Control Transactions. Entities and assets acquired from ETE and its affiliates are accounted for as common control transactions whereby the net assets acquired are combined with the Partnership's net assets at their historical amounts. If consideration transferred differs from the carrying value of the net assets acquired, the excess or deficiency is treated as a capital transaction similar to a dividend or capital contribution. To the extent that such transactions require prior periods to be recast, historical net equity amounts prior to the transaction date are reflected in predecessor equity.

Cash and Cash Equivalents. Cash and cash equivalents include temporary cash investments with original maturities of three months or less.

Equity Method Investments. The equity method of accounting is used to account for the Partnership's interest in investments of greater than 20% voting interest or where the Partnership exerts significant influence over an investee but lacks control over the investee. Even though there is a presumption of a controlling financial interest in Aqua - PVR (because of our 51% ownership), our partner in this joint venture has substantive participating rights and management authority that preclude us from controlling the joint venture. Therefore, it is accounted for as an equity method investment. The Partnership acquired a 50% interest in Coal Handling as part of the PVR Acquisition and purchased the remaining 50% interest effective December 31, 2014 for $16 million, resulting in a gain on the purchase due to the revaluation of the Partnership's previously held non-controlling interest.

Inventories. Inventories are valued at the lower of cost or market and include materials and parts primarily utilized by the Contract Services and Gathering & Processing segments.

Property, Plant and Equipment. Property, plant and equipment is recorded at historical cost of construction or, upon acquisition, the fair value of the assets acquired. Gains or losses on sales or retirements of assets are included in operating income unless the disposition is treated as discontinued operations. Natural gas and NGLs used to maintain pipeline minimum pressures is classified as property, plant and equipment. Financing costs associated with the construction of larger assets requiring ongoing efforts over a period of time are capitalized. For the years ended December 31, 2014, 2013 and 2012, the Partnership capitalized interest of $14 million, $2 million and $1 million, respectively. The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Expenditures to extend the useful lives of the assets are capitalized.

Depreciation expense related to property, plant and equipment was $418 million, $258 million, and $219 million for the years ended December 31, 2014, 2013 and 2012, respectively. In March 2012, the Partnership recorded a $7 million “out-of-period” adjustment to depreciation expense to correct the estimated useful lives of certain assets to comply with its policy.

Depreciation of property, plant and equipment is recorded on a straight-line basis over the following estimated useful lives:

Functional Class of Property	Useful Lives (Years)
Gathering and Transmission Systems	20 - 40
Compression Equipment	2 - 30
Gas Plants and Buildings	5 - 20
Other Property, Plant and Equipment	3 - 15

Depletion expense related to the Natural Resources segment was $11 million for the year ended December 31, 2014. Coal properties are depleted on an area-by-area basis at a rate based on the cost of the mineral properties and the number of tons of estimated proven and probable coal reserves contained therein. Proven and probable coal reserves have been estimated by the Partnership’s own geologists. The Partnership’s estimates of coal reserves are updated periodically and may result in adjustments to coal reserves and depletion rates that are recognized prospectively. From time to time, the Partnership carries out core-hole drilling activities on coal properties in order to ascertain the quality and quantity of the coal contained in those properties. These core-hole drilling activities are expensed as incurred. The Partnership depletes timber using a methodology consistent with the units-of-production method, which is based on the quantity of timber harvested. The Partnership determines depletion of oil and gas royalty interests by the units-of-production method and these amounts could change with revisions to estimated proved recoverable reserves.

Intangible Assets. As of December 31, 2014, intangible assets consisted of trade names and customer relations, and are amortized on a straight line basis over their estimated useful lives, which is the period over which the assets are expected to contribute directly or indirectly to the Partnership’s future cash flows. The estimated useful lives range from 8 to 30 years.

The Partnership assesses long-lived assets, including property, plant and equipment and intangible assets, for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability is assessed by comparing the carrying amount of an asset to undiscounted future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured as the amount by which the carrying amounts exceed the fair value of the assets. The Partnership did not record any impairment in 2014, 2013, or 2012.

Goodwill. Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired in a business combination. Goodwill is not amortized, but is tested for impairment annually based on the carrying values as of November 30 or December 31 depending upon the reporting unit, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered. The Partnership has the option to first assess qualitative factors to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount as a basis for determining whether further impairment testing is necessary. Impairment is indicated when the carrying amount of a reporting unit exceeds its fair value. To estimate the fair value of the reporting units, the Partnership makes estimates and judgments about future cash flows, as well as revenues, cost of sales, operating expenses, capital expenditures and net working capital based on assumptions that are consistent with the Partnership’s most recent forecast. At the time it is determined that an impairment has occurred, the carrying value of the goodwill is written down to its fair value.

In 2014, a $370 million goodwill impairment charge was recorded related to the Permian reporting unit within the Gathering and Processing segment. The decline in estimated fair value of that reporting unit is primarily driven by the significant decline in commodity prices in the fourth quarter of 2014, and the resulting impact to future commodity prices as well as increases in future estimated operations and maintenance expenses. As a result of the Partnership’s determination that the estimated fair value of the reporting unit being less than the carrying value, the Partnership performed the second step of the goodwill impairment assessment, which requires the assets and liabilities of the reporting unit to be fair valued on a hypothetical basis. Any excess value over the estimated fair value of the reporting unit, determined in this case through established valuation techniques such as discounted cash flow methods and market comparable analyses, compared to the hypothetical fair value of all assets and liabilities of the reporting unit is the implied fair value of goodwill. To the extent that the implied fair value of goodwill is less than the carrying value of goodwill, an impairment is recognized to eliminate any excess carrying amounts.

No other goodwill impairments were identified or recorded for the Partnership's other reporting units in 2014. No goodwill impairment charges were incurred in 2013 or 2012.

Other Assets, net. Other assets, net primarily consists of debt issuance costs, which are capitalized and amortized to interest expense, net over the life of the related debt.

Gas Imbalances. Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements are recorded monthly as other current assets or other current liabilities using then current market prices or the weighted average prices of natural gas or NGLs at the plant or system pursuant to imbalance agreements for which settlement prices are not contractually established.

Within certain volumetric limits determined at the sole discretion of the creditor, these imbalances are generally settled by deliveries of natural gas. Imbalance receivables and payables as of December 31, 2014 and 2013 were immaterial.

Asset Retirement Obligations. Legal obligations associated with the retirement of long-lived assets are recorded at fair value at the time the obligations are incurred, if a reasonable estimate of fair value can be made. Present value techniques are used which reflect assumptions such as removal and remediation costs, inflation, and profit margins that third parties would demand to settle the amount of the future obligation. The Partnership does not include a market risk premium for unforeseeable circumstances in its fair value estimates because such a premium cannot be reliably estimated. Upon initial recognition of the liability, costs are capitalized as a part of the long-lived asset and allocated to expense over the useful life of the related asset. The liability is accreted to its present value each period with accretion being recorded to operating expense with a corresponding increase in the carrying amount of the liability. The ARO assets and liabilities were immaterial as of December 31, 2014.

Environmental. The Partnership's operations are subject to federal, state and local laws and rules and regulations regarding water quality, hazardous and solid waste management, air quality control and other environmental matters. These laws, rules and regulations require the Partnership to conduct its operations in a specified manner and to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with applicable environmental laws, rules and regulations may expose the Partnership to significant fines, penalties and/or interruptions in operations. The Partnership's environmental policies and procedures are designed to achieve compliance with such applicable laws and regulations. These evolving laws and regulations and claims for damages to property, employees, other persons and the environment resulting from current or past operations may result in significant expenditures and liabilities in the future.

Predecessor Equity. Predecessor equity included on the consolidated statements of partners' capital and noncontrolling interest represents SUGS member's capital prior to the acquisition date (April 30, 2013).

Revenue Recognition. The Partnership earns revenue from (i) domestic sales of natural gas, NGLs and condensate, (ii) natural gas, NGL, condensate, and salt water gathering, processing and transportation, (iii) contract compression and treating services, and (iv) coal royalties. Revenue associated with sales of natural gas, NGLs and condensate are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery occurs. Revenue associated with transportation and processing fees are recognized when the service is provided. For contract compression and contract treating services, revenue is recognized when the service is performed. For gathering and processing services, the Partnership receives either fees or commodities from natural gas producers depending on the type of contract. Commodities received are in turn sold and recognized as revenue in accordance with the criteria outlined above. Under the percentage-of-proceeds contract type, the Partnership is paid for its services by keeping a percentage of the NGLs produced and a percentage of the residue gas resulting from processing the natural gas. Under the percentage-of-index contract type, the Partnership earns revenue by purchasing wellhead natural gas at a percentage of the index price and selling processed natural gas and NGLs at a price approximating the index price to third parties. The Partnership generally reports revenue gross in the consolidated statements of operations when it acts as the principal, takes title to the product, and incurs the risks and rewards of ownership. Revenue for fee-based arrangements is presented net, because the Partnership takes the role of an agent for the producers. Allowance for doubtful accounts is determined based on historical write-off experience and specific identification.

Coal Royalties Revenues and Deferred Income. The Partnership recognizes coal royalties revenues on the basis of tons of coal sold by its lessees and the corresponding revenues from those sales. The Partnership does not have access to actual production and revenues information until 30 days following the month of production. Therefore, financial results include estimated revenues and accounts receivable for the month of production. The Partnership records any differences between the actual amounts ultimately received or paid and the original estimates in the period they become finalized. Most lessees must make minimum monthly or annual payments that are generally recoverable over certain time periods. These minimum payments are recorded as deferred income. If the lessee recovers a minimum payment through production, the deferred income attributable to the minimum payment is recognized as coal royalties revenues. If a lessee fails to meet its minimum production for certain pre-determined time periods, the deferred income attributable to the minimum payment is recognized as minimum rental revenues, which is a component of other revenues on our consolidated statements of operations. Other liabilities on the balance sheet also include deferred unearned income from a coal services facility lease, which is recognized in other income as it is earned.

Derivative Instruments. The Partnership's net income and cash flows are subject to volatility stemming from changes in market prices such as natural gas prices, NGLs prices, processing margins and interest rates. The Partnership uses product-specific swaps to create offsetting positions to specific commodity price exposures, and uses interest rate swap contracts to create offsetting positions to specific interest rate exposures. Derivative financial instruments are recorded on the balance sheet at their fair value based on their settlement date. The Partnership employs derivative financial instruments in connection with an underlying asset, liability and/or anticipated transaction and not for speculative purposes. Furthermore, the Partnership regularly assesses the creditworthiness of counterparties to manage the risk of default. As of December 31, 2014 and 2013, no derivative financial instruments were designated as hedges. In the statement of cash flows, the effects of settlements of derivative instruments are classified consistent with the related hedged transactions.

Benefits. The Partnership provides medical, dental, and other healthcare benefits to employees. The total amount incurred by the Partnership for the years ended December 31, 2014, 2013 and 2012, was $17 million, $9 million and $9 million, respectively, in operation and maintenance and general and administrative expenses, as appropriate. The Partnership also provides a matching contribution to its employee's 401(k) accounts which vest immediately upon contribution. The total amount of matching contributions for the years ended December 31, 2014, 2013 and 2012 was $9 million, $7 million and $4 million, respectively, and were recorded in operation and maintenance and general and administrative expenses, as appropriate. The Partnership has no pension obligations or other post-employment benefits. Beginning January 1, 2013, the Partnership provides a 3% profit sharing contribution to employee 401(k) accounts for all employees with base compensation below a specified threshold. The contribution is in addition to the 401(k) matching contribution and employees become vested based on years of service.

Income Taxes. The Partnership is generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. The Partnership is subject to the gross margins tax enacted by the state of Texas. The Partnership has one wholly-owned subsidiary that is subject to income tax and provides for deferred income taxes using the asset and liability method. Accordingly, deferred taxes are recorded for differences between the tax and book basis that will reverse in future periods. The Partnership has deferred tax liabilities of $20 million and $22 million as of December 31, 2014 and 2013, respectively, related to the difference between the book and tax basis of property, plant and equipment and intangible assets and they are included in other long-term liabilities in the accompanying consolidated balance sheets. The Partnership follows the guidance for uncertainties in income taxes where a liability for an unrecognized tax benefit is recorded for a tax position that does not meet the "more likely than not" criteria. The Partnership has not recorded any uncertain tax positions meeting the more likely than not criteria as of December 31, 2014 and 2013. The Partnership recognized $3 million for current and deferred federal and state income tax for the year ended December 31, 2014 and an immaterial amount for current and deferred federal and state income tax benefit for the years ended December 31, 2013 and 2012.

Effective with the Partnership's acquisition of SUGS on April 30, 2013, SUGS is generally no longer subject to federal income taxes and subject only to gross margins tax in the state of Texas. Substantially all previously recorded current and deferred tax liabilities were settled with Southern Union, along with all other intercompany receivables and payables at the date of acquisition.

The Partnership has its 2007 and 2008 tax years under audit by the IRS. Until this matter is fully resolved, it is not known whether any amounts ultimately recorded would be material, or how such adjustments would affect unitholders. The statute of limitations for these audits has been extended to December 31, 2015.

Equity-Based Compensation. The Partnership accounts for common unit options and phantom units by recognizing the grant-date fair value of awards into expense as they are earned, using an estimated forfeiture rate. The forfeiture rate assumption is reviewed annually to determine whether any adjustments to expense are required. Cash restricted units are recorded in other long-term liabilities on our consolidated balance sheet. The fair value of cash restricted units is remeasured at the end of each reporting period, based on the trading price of our common units, and compensation expense is recorded using the straight-line method over the vesting period.

Earnings per Unit. Basic net income per common unit is computed through the use of the two-class method, which allocates earnings to each class of equity security based on their participation in distributions and deemed distributions. Accretion of the Series A Preferred Units is considered as deemed distributions. Distributions and deemed distributions to the Series A Preferred Units reduce the amount of net income available to the general partner and limited partner interests. The general partners' interest in net income or loss consists of its respective percentage interest, make-whole allocations for any losses allocated in a prior tax year and IDRs. After deducting the General Partner's interest, the limited partners' interest in the remaining net income or loss is allocated to each class of equity units based on distributions and beneficial conversion feature amounts, if applicable, then divided by the weighted average number of common and subordinated units outstanding in each class of security. Diluted net income per common unit is computed by dividing limited partners' interest in net income, after deducting the General Partner's interest, by the weighted average number of units outstanding and the effect of non-vested phantom units, Series A Preferred Units and unit options. For special classes of common units, such as the Class F units issued with a beneficial conversion feature, the amount of the benefit associated with the period is added back to net income and the unconverted class is added to the denominator.

New Accounting Pronouncement. In May 2014, the FASB issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASU 2014-09"), which clarifies the principles for recognizing revenue based on the core principle that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period, with earlier adoption not permitted. ASU 2014-09 can be adopted either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment as of the date of adoption. The Partnership is currently evaluating the impact, if any, that adopting this new accounting standard will have on our revenue recognition policies.

3. PARTNERS' CAPITAL AND DISTRIBUTIONS

Units Activity. The changes in common and Class F units were as follows:

	Common	Class F
Balance - December 31, 2011	157,437,608	—
Common unit offerings, net of costs	12,650,000	—
Issuance of common units under the equity distribution agreement, net of cost	691,129	—
Issuance of common units under LTIP, net of forfeitures and tax withholding	172,720	—
Balance - December 31, 2012	170,951,457	—
Issuance of common units under LTIP, net of forfeitures and tax withholding	184,995	—
Issuance of common units under the equity distribution agreement, net of cost	5,712,138	—
Conversion of Series A preferred units for common units	2,629,223	—
Issuance of common units and Class F units in connection with SUGS Acquisition	31,372,419 (1)	6,274,483 (2)
Balance - December 31, 2013	210,850,232	6,274,483
Issuance of common units under LTIP, net of forfeitures and tax withholding	163,054	—
Issuance of common units under the equity distribution agreements	14,827,919	—
Issuance of common units in connection with Hoover Acquisition	4,040,471	—
Issuance of common units in connection with PVR Acquisition	140,388,382	—
Issuance of common units in connection with Eagle Rock Midstream Acquisition	8,245,859	—
Issuance of common units to ETE Common Holdings	30,890,565	—
Balance - December 31, 2014	409,406,482	6,274,483

(1) ETE has agreed to forgo IDR payments on the Partnership common units issued with the SUGS Acquisition for twenty-four months post-transaction closing.
(2) The Class F units are not entitled to participate in the Partnership's distributions or earnings for twenty-four months post-transaction closing.

Equity Distribution Agreement. In June 2012, the Partnership entered into an equity distribution agreement with Citi under which the Partnership offered and sold common units for an aggregate offering price of $200 million, from time to time through Citi, as sales agent for the Partnership. Sales of these common units made from time to time under the equity distribution agreement were made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices, in block transactions, or as otherwise agreed upon by the Partnership and Citi. The Partnership used the net proceeds from the sale of these common units for general partnership purposes. For the years ended December 31, 2014 and 2013, the Partnership received net proceeds of $34 million and $149 million, respectively, from common units sold pursuant to this equity distribution agreement. No amounts remain available to be issued under this agreement and it is no longer effective.

In May 2014, the Partnership entered into an equity distribution agreement with a group of banks and investment companies (the "Managers") under which the Partnership offered and sold common units for an aggregate offering price of $400 million, from time to time through the Managers, as sales agent for the Partnership. Sales of these units made from time to time under the equity distribution agreement were made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices, in block transactions, or as otherwise agreed upon by the Partnership and the Managers. The Partnership used the net proceeds from the sale of these units for general partnership purposes. For the year ended December 31, 2014, the Partnership received net proceeds of $395 million from common units sold pursuant to this equity distribution agreement. No amounts remained available to be issues under this agreement and it is no longer effective.

In January 2015, the Partnership entered into an equity distribution agreement with another group of banks and investment companies (the "2015 Managers") under which the Partnership may offer and sell common units for an aggregate offering price of up to $1 billion, from time to time through the 2015 Managers, as sales agent for the Partnership. Sales of these common units made from time to time under the equity distribution agreement will be made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices, in block transactions, or as otherwise agreed upon by the Partnership and the 2015 Managers. The Partnership may also sell common units to the 2015 Managers as principal for their own accounts at a price agreed upon at the time of sale. Any sale of common units to the 2015 Managers as principal would be pursuant to the terms of a separate agreement between the Partnership and the 2015 Managers. The Partnership intends to use the net proceeds from the sale of these common units for general partnership purposes.

Common Units Sold. In June 2014, the Partnership sold 14.4 million common units to ETE Common Holdings for proceeds of $400 million. Proceeds from the issuance were used to pay down borrowings on the Partnership's revolving credit facility, to redeem certain senior notes of the Partnership and for general partnership purposes. In July 2014, the Partnership sold 16.5 million common units to ETE Common Holdings for proceeds of $400 million. Proceeds from the issuance were used to fund a portion of the cash consideration paid to Eagle Rock in connection with the Eagle Rock Midstream Acquisition.

Public Common Unit Offerings. In March 2012, the Partnership issued 12,650,000 common units representing limited partner interests in a public offering at a price of $24.47 per common unit, resulting in net proceeds of $297 million. In May 2012, the Partnership used the net proceeds from this offering to redeem 35%, or $88 million, in aggregate principal amounts of its outstanding senior notes due 2016; pay related premium, expenses and accrued interest; and repay outstanding borrowings under the revolving credit facility.

Beneficial Conversion Feature. The Partnership issued 6,274,483 Class F units in connection with the SUGS Acquisition. At the commitment date (February 27, 2013), the sales price of $23.91 per unit represented a $2.19 per unit discount from the fair value of the Partnership's common units as of April 30, 2013. Under FASB ASC 470-20, "*Debt with Conversion and Other Options*," the discount represents a beneficial conversion feature that is treated as a non-cash distribution for purposes of calculating earnings per unit. The beneficial conversion feature is reflected in income per unit using the effective yield method over the period the Class F units are outstanding, as indicated on the statement of operations in the line item entitled "beneficial conversion feature for Class F units." The Class F units are convertible to common units on a one-for-one basis on May 8, 2015.

Noncontrolling Interest. The Partnership operates ELG, a gas gathering joint venture in south Texas in which other third party companies own a 40% interest, and ORS, a gathering joint venture in Ohio in which a third party company owns a 25% interest, which are reflected on the Partnership's consolidated balance sheet as noncontrolling interest.

Distributions. The partnership agreement requires the distribution of all of the Partnership's Available Cash (defined below) within 45 days after the end of each quarter to unitholders of record on the applicable record date, as determined by the General Partner.

Available Cash. Available Cash, for any quarter, generally consists of all cash and cash equivalents on hand at the end of that quarter less the amount of cash reserves established by the general partner to: (i) provide for the proper conduct of the Partnership's business; (ii) comply with applicable law, any debt instruments or other agreements; or (iii) provide funds for distributions to the unitholders and to the General Partner for any one or more of the next four quarters and plus, all cash on hand on that date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter for which the determination is being made.

General Partner Interest and Incentive Distribution Rights. The General Partner is entitled to its proportionate share of all quarterly distributions that the Partnership makes prior to its liquidation. The General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership to maintain its current general partner interest. The General Partner's initial 2% interest in these distributions has been reduced since the Partnership has issued additional units and the General Partner has not contributed a proportionate amount of capital to the Partnership to maintain its General Partner interest. The General Partner ownership interest as of December 31, 2014 was 0.69%. This General Partner interest is represented by 2,834,381 equivalent units as of December 31, 2014.

The IDRs held by the General Partner entitle it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. The General Partner's IDRs are not reduced if the Partnership issues additional units in the future and the general partner does not contribute a proportionate amount of capital to the Partnership to maintain its general partner interest.

In connection with the SUGS Acquisition, ETE agreed to forgo IDR payments on the Partnership common units issued with this transaction for the twenty-four months post-transaction closing.

Distributions. The Partnership made the following cash distributions per unit during the years ended December 31, 2014 and 2013:

Distribution Date	Cash Distribution (per common unit)	
November 14, 2014	$	0.5025
August 14, 2014		0.490
May 15, 2014		0.480
February 14, 2014		0.475
November 14, 2013	$	0.470
August 14, 2013		0.465
May 13, 2013		0.460
February 14, 2013		0.460

The Partnership paid a cash distribution of $0.5025 per common unit on February 13, 2015.

4. (LOSS) INCOME PER LIMITED PARTNER UNIT

The following table provides a reconciliation of the numerator and denominator of the basic and diluted (loss) earnings per unit computations for the years ended December 31, 2014, 2013, and 2012.

	Years Ended December 31,								
	2014			2013			2012		
	Loss (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
Basic (loss) income per unit									
Limited Partners' interest in net (loss) income	$ (199)	348,070,121	$ (0.57)	$ 34	196,227,348	$ 0.17	$ 27	167,492,735	$ 0.16
Effect of Dilutive Securities:									
Common unit options	—	—		—	22,714		—	10,854	
Phantom units *	—	—		—	357,230		—	223,325	
Series A Preferred Units	—	—		—	2,050,854		(5)	4,658,700	
Diluted (loss) income per unit	$ (199)	348,070,121	$ (0.57)	$ 34	198,658,146	$ 0.17	$ 22	172,385,614	$ 0.13

* Amount assumes maximum conversion rate for market condition awards.

The following data show securities that could potentially dilute earnings per unit in the future that were not included in the computation of diluted earnings per unit because to do so would have been antidilutive for the period presented:

	Year Ended December 31, 2014
Common unit options	25,959
Phantom units	469,264
Series A Preferred Units	2,059,503

The partnership agreement requires that the General Partner shall receive a 100% allocation of income until its capital account is made whole for all of the net losses allocated to it in prior years.

5. ACQUISITIONS

2014

Eagle Rock Midstream Acquisition. On July 1, 2014, the Partnership acquired Eagle Rock's midstream business (the "Eagle Rock Midstream Acquisition") for $1.3 billion, including the issuance of 8.2 million Regency common units to Eagle Rock and the assumption of $499 million of Eagle Rock's 8.375% Senior Notes due 2019. The remainder of the purchase price was funded by $400 million in common units issued to ETE Common Holdings and borrowings under the Partnership's revolving credit facility. The Partnership accounted for the Eagle Rock Midstream Acquisition using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized on the balance sheet at their fair values as of the acquisition date. This acquisition complemented the Partnership's core gathering and processing business and further diversified the Partnership's geographic presence in the mid-continent region, east Texas and south Texas. Revenues and net income attributable to Eagle Rock's operations included in the statement of operations for the year ended December 31, 2014 were $903 million and $30 million, respectively.

Management's evaluation of the assigned fair values is ongoing. The table below represents a preliminary allocation of the total purchase price:

Assets		At July 1, 2014
Current assets	$	120
Property, plant and equipment		1,295
Other long-term assets		4
Goodwill [(1)]		49
Total Assets Acquired	$	1,468
Liabilities		
Current liabilities	$	116
Long-term debt		499
Long-term liabilities		12
Total Liabilities Assumed	$	627
Net Assets Acquired	$	841

[(1)] Goodwill is reported in the Gathering and Processing segment.

The fair values of the assets acquired and liabilities assumed is being determined using various valuation techniques, including the income and market approaches.

PVR Acquisition. On March 21, 2014, the Partnership acquired PVR for a total purchase price of $5.7 billion, including $1.8 billion principal amount of assumed debt ("PVR Acquisition"). PVR unitholders received (on a per unit basis) 1.02 Partnership common units and a one-time cash payment of $36 million, which was funded through borrowings under the Partnership's revolving credit facility. The PVR Acquisition enhanced the Partnership's geographic diversity by adding a strategic presence in the Marcellus and Utica shales in the Appalachian Basin and the Granite Wash in the Mid-Continent region. The Partnership accounted for the acquisition of PVR using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized on the balance sheet at their fair values as of the acquisition date. Revenues and net income attributable to PVR's operations included in the statement of operations for the year ended December 31, 2014 were $956 million and $166 million, respectively.

Management completed the evaluation of the assigned fair values to the assets acquired and liabilities assumed. The total purchase price was allocated as follows:

Assets		**At March 21, 2014**
Current assets	$	149
Gathering and transmission systems		1,396
Compression equipment		342
Gas plants and buildings		110
Natural resources		454
Other property, plant and equipment		229
Construction in process		185
Investments in unconsolidated affiliates		62
Intangible assets		2,717
Goodwill [(1)]		370
Other long-term assets		18
Total Assets Acquired	$	6,032
Liabilities		
Current liabilities	$	168
Long-term debt		1,788
Premium related to senior notes		99
Long-term liabilities		30
Total Liabilities Assumed	$	2,085
Net Assets Acquired	$	3,947

[(1)] Goodwill is reported in the Gathering and Processing segment.

The fair values of the assets acquired and liabilities assumed were determined using various valuation techniques, including the income and market approaches.

Assets. Cash and cash equivalents, accounts receivable, net, other current assets, and construction in process, were valued using a cost basis as this basis approximates fair value due to the current nature of these items. Real property, including gathering and transmission systems, compression equipment, gas plants and buildings, and other property, plant and equipment, were valued based on a combination of the income, market and cost approaches, depending on the type of asset. Coal and timber reserves were valued using the income approach for active coal and timber reserves. The investments in unconsolidated affiliates were valued using the income approach. Intangible assets, other than goodwill, are customer contract related intangibles, which have an average useful life of 30 years, and have been valued using the income approach. The goodwill is the excess of the consideration transferred over the net assets recognized and represents the future economic benefits arising from other assets acquired that could not be individually identified and separately recognized.

Liabilities. The Partnership assumed accounts payable, accrued liabilities, deferred income, and other long-term liabilities as part of the PVR Acquisition. The Partnership determined that the historical cost basis of these liabilities approximated fair value as they comprise normal operating liabilities. The Partnership assumed long-term debt as part of the acquisition, consisting of amounts outstanding under PVR's revolving credit facility and PVR's outstanding senior notes. The amount related to the revolving credit facility was valued at historical book value while the senior notes were valued using quoted market prices, which are considered Level 1 inputs.

Change in Control. The PVR Acquisition constituted a change of control for certain PVR employment agreements. Pursuant to the terms of those agreements, certain payments and benefits, including severance payments, were triggered by the PVR Acquisition. The Partnership recorded $10 million of severance payments due to the change in control and recorded $2 million in retention bonuses that were paid to various retained PVR employees upon the expiration of their retention period.

Hoover Energy Acquisition. On February 3, 2014, the Partnership acquired certain subsidiaries of Hoover for a total purchase price of $293 million, consisting of (i) 4,040,471 common units issued to Hoover and (ii) $184 million in cash, and (iii) $2 million in asset retirement obligations assumed (the "Hoover Acquisition"). The Hoover Acquisition increased the Partnership's fee-based revenue, expanding its existing footprint in the southern portion of the Delaware Basin in west Texas, and its services to producers into crude and water gathering. A portion of the consideration is in escrow as security for certain indemnification claims. The Partnership financed the cash portion of the purchase price through borrowings under its revolving credit facility. The Partnership accounted for the Hoover Acquisition using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized on the balance sheet at their fair values as of the acquisition date. Revenues and net income attributable to Hoover's operations included in the statement of operations for the year ended December 31, 2014 were $35 million and less than $1 million, respectively.

Management completed the evaluation of the assigned fair values to the assets acquired and liabilities assumed. The total purchase price was allocated as follows:

Assets		**At February 3, 2014**
Accounts receivable, net	$	5
Gathering and transmission systems		60
Compression equipment		16
Gas plants and buildings		12
Other property, plant, and equipment		23
Construction in process		6
Intangible assets		148
Goodwill [(1)]		30
Total Assets Acquired	$	300
Liabilities		
Accounts payable and accrued liabilities	$	5
Asset retirement obligation		2
Total Liabilities Assumed	$	7
Net Assets Acquired	$	293

[(1)] Goodwill is reported in the Gathering and Processing segment.

The fair values of the assets acquired and liabilities assumed were determined using various valuation techniques, including the income and market approaches.

Assets. Accounts receivable, net, other current assets, and construction in process were valued using a cost basis as this basis approximates fair value due to the current nature of these items. Real property, including gathering and transmission systems, compression equipment, and other property, plant and equipment, were valued based on a combination of the income, market and cost approaches, depending on the type of asset. Intangible assets, other than goodwill, are customer contract related intangibles, which have an average useful life of 30 years, and have been valued using the income approach. The goodwill is the excess of the consideration transferred over the net assets recognized and represents the future economic benefits arising from other assets acquired that could not be individually identified and separately recognized.

Liabilities. The Partnership assumed accounts payable, accrued liabilities, and an asset retirement obligation as part of the Hoover Acquisition. The Partnership determined that the historical cost basis of the accounts payable and the accrued liabilities approximated fair value as they comprise normal operating liabilities. The asset retirement obligation was valued based on estimates prepared by an independent environmental consulting firm.

Pro Forma Results of Operations

The following unaudited pro forma consolidated results of operations for the years ended December 31, 2014 and 2013 are presented as if the PVR, Hoover and Eagle Rock Midstream acquisitions had been completed on January 1, 2013. The pro forma information includes adjustments to reflect incremental expenses associated with the fair value adjustments recorded as a result of applying the acquisition method of accounting and incremental interest expense related to the financing of a portion of the purchase price. This pro forma information is not necessarily indicative of the results that would have occurred had the acquisitions occurred on January 1, 2013, nor is it indicative of future results of operations. Actual results for the year ended December 31, 2014 include PVR, Hoover, and the Eagle Rock midstream business from their respective dates of acquisition.

	Years Ended December 31,	
	2014	2013
Revenues	$ 5,780	$ 4,695
Net loss attributable to the Partnership	(252)	(195)
Basic net loss per Limited Partner unit	$ (0.76)	$ (0.50)
Diluted net loss per Limited Partner unit	$ (0.76)	$ (0.50)

2013

SUGS Acquisition. In April 2013, the Partnership acquired SUGS from Southern Union, a wholly-owned subsidiary of Holdco, for $1.5 billion (the "SUGS Acquisition").

The Partnership accounted for the SUGS Acquisition in a manner similar to the pooling of interest method of accounting as it was a transaction between commonly controlled entities. The Partnership retrospectively adjusted its financial statements to include the balances and operations of SUGS for periods March 26, 2012 to April 30, 2013. The SUGS Acquisition did not impact historical earnings per unit as pre-acquisition earnings were allocated to predecessor equity.

The assets acquired and liabilities assumed in the SUGS Acquisition were as follows:

	April 30, 2013
Current assets	$ 113
Property, plant and equipment, net	1,608
Goodwill	337
Other non-current assets	1
Total Assets Acquired	$ 2,059
Less:	
Current liabilities	(93)
Non-current liabilities	(36)
Net Assets Acquired	$ 1,930

The following table presents the revenues and net income (loss) for the previously separate entities and combined amounts presented herein:

	Years Ended December 31,	
	2013 [(1)]	2012
Revenues:		
Partnership	$ 2,253	$ 1,339
SUGS [(1)]	268	661
Combined	$ 2,521	$ 2,000
Net income (loss):		
Partnership	$ 63	$ 48
SUGS [(1)]	(36)	(14)
Combined	$ 27	$ 34

(1) Combined amounts attributable to SUGS include the period from March 26, 2012 to December 31, 2012 for the year ended December 31, 2012, and the period from January 1, 2013 to April 30, 2013 for the year ended December 31, 2013. Subsequent to the closing of the SUGS Acquisition on April 30, 2013, the results of SUGS were attributable to the Partnership.

6. INVESTMENTS IN UNCONSOLIDATED AFFILIATES

The carrying value of the Partnership's investment in each of the unconsolidated affiliates as of December 31, 2014 and 2013 is as follows:

			December 31,	
	Ownership	Type	2014	2013
HPC	49.99%	General Partner	$ 422	$ 442
MEP	50.00%	Membership Interest	695	549
Lone Star	30.00%	Membership Interest	1,162	1,070
Ranch JV	33.33%	Membership Interest	38	36
Aqua - PVR	51.00%	Membership Interest	46	—
Mi Vida JV	50.00%	Membership Interest	54	—
Others [(1)]			1	—
			$ 2,418	$ 2,097

(1) Others includes Coal Handling, Sweeny JV and Grey Ranch

The Partnership's interests in the Aqua - PVR joint venture was acquired in the PVR Acquisition. In March 2014, the Partnership entered into an agreement, whereby the Partnership's 50% interest in Grey Ranch was assigned to SandRidge Midstream, Inc., resulting in a cash settlement of $4 million and a loss of $1 million recorded to income from unconsolidated affiliates.

The following tables summarize the changes in the Partnership's investment activities in each of the unconsolidated affiliates for the years ended December 31, 2014, 2013 and 2012:

	Year Ended December 31, 2014						
	HPC	MEP [(2)]	Lone Star	Ranch JV	Aqua - PVR	Mi Vida JV	Others [(4)]
Contributions to unconsolidated affiliates	$ —	$ 175	$ 114	$ —	$ —	$ 54	$ —
Distributions from unconsolidated affiliates	(48)	(73)	(137)	(8)	(1)	—	(4)
Share of earnings of unconsolidated affiliates' net income (loss)	33	45	116	9	(4)	—	2
Amortization of excess fair value of investment [(1)]	(6)	—	—	—	—	—	—

	Year Ended December 31, 2013				
	HPC [3]	MEP	Lone Star	Ranch JV	Others [4]
Contributions to unconsolidated affiliates	$ —	$ —	$ 137	$ 2	$ —
Distributions from unconsolidated affiliates	(238)	(72)	(79)	(2)	—
Share of earnings of unconsolidated affiliates' net income	36	40	64	1	—
Amortization of excess fair value of investment [1]	(6)	—	—	—	—

	Year Ended December 31, 2012				
	HPC	MEP	Lone Star	Ranch JV	Others [4]
Contributions to unconsolidated affiliates	$ —	$ —	$ 343	$ 36	$ —
Distributions from unconsolidated affiliates	(61)	(75)	(68)	—	—
Share of earnings of unconsolidated affiliates' net income (loss)	35	42	44	(1)	(9)
Amortization of excess fair value of investment [1]	(6)	—	—	—	—

(1) The Partnership's investment in HPC was adjusted to its fair value on May 26, 2010 and the excess fair value over net book value was comprised of two components: (1) $155 million was attributed to HPC's long-lived assets and is being amortized as a reduction of income from unconsolidated affiliates over the useful lives of the respective assets, which vary from 15 to 30 years, and (2) $32 million could not be attributed to a specific asset and therefore will not be amortized in future periods.

(2) The Partnership contributed $175 million to MEP in September 2014 for the repayment of MEP's debt.

(3) HPC entered into a $500 million 5-year revolving credit facility in September 2013, pursuant to which the Partnership pledged its 49.99% equity interest in HPC. Upon closing such credit facility, HPC borrowed $370 million to fund a non-recurring return of investment to its partners of which the Partnership received $185 million. The amount outstanding under this facility was $450 million as of December 31, 2014. The Partnership's contingent obligation with respect to the outstanding borrowings under this facility was $225 million at December 31, 2014.

(4) Includes Coal Handling, Grey Ranch, and Sweeny JV.

Summarized Financial Information

Consolidated financial statements for HPC, MEP, and Lone Star are filed as exhibits to this Form 10-K. The following tables present aggregated selected balance sheet and income statement data for Ranch JV (on a 100% basis) for all periods presented:

	December 31,	
	2014	2013
Current assets	$ 16	$ 7
Property, plant and equipment, net	95	100
Other assets	4	4
Total assets	$ 115	$ 111
Current liabilities	$ 2	$ 3
Equity	113	108
Total liabilities and equity	$ 115	$ 111

	Years Ended December 31,		
	2014	2013	2012
Revenue	$ 41	$ 16	$ 1
Operating income (loss)	29	4	(2)
Net income (loss)	29	4	(2)

7. DERIVATIVE INSTRUMENTS

Policies. The Partnership established comprehensive risk management policies and procedures to monitor and manage the market risks associated with commodity prices, counterparty credit and interest rates. The General Partner is responsible for delegation of transaction authority levels, and the Audit and Risk Committee of the General Partner is responsible for overseeing the management of these risks, including monitoring exposure limits. The Audit and Risk Committee receives regular briefings on exposures and overall risk management in the context of market activities.

Commodity Price Risk. The Partnership is a net seller of NGLs, condensate and natural gas as a result of its gathering and processing operations. The prices of these commodities are impacted by changes in supply and demand as well as market forces. Both the Partnership's profitability and cash flow are affected by the inherent volatility of these commodities which could adversely affect its ability to make distributions to its unitholders. The Partnership manages this commodity price exposure through an integrated strategy that includes management of its contract portfolio, matching sales prices of commodities with purchases, optimization of its portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, the Partnership may not be able to match pricing terms or cover its risk to price exposure with financial hedges, and it may be exposed to commodity price risk.

The Partnership has swap contracts settled against certain NGLs, condensate and natural gas market prices.

Marketing & Trading. The Partnership conducts natural gas marketing and trading activities intended to capitalize on favorable price differentials between various receipt and delivery locations. The Partnership enters into both financial derivatives and physical contracts. These financial derivatives, primarily basis swaps, are transacted: (i) to economically hedge subscribed capacity exposed to market rate fluctuations and (ii) to mitigate the price risk related to other purchases and sales of natural gas. By entering into a basis swap, one pricing index is exchanged for another, effectively locking in the margin between the natural gas purchase and sale by removing index spread risk on the combined physical and financial transaction. Changes in the fair value of these financial and physical contracts are recorded as adjustments to natural gas sales and realized (unrealized) gain (loss) from derivatives, as appropriate.

The Partnership has credit exposure to additional counterparties. The Partnership monitors its exposure to any single counterparty and the creditworthiness of its counterparties on an ongoing basis. In addition, the Partnership's natural gas purchase and sale contracts, for certain counterparties, are subject to counterparty netting agreements governing settlement under such natural gas purchase and sales contracts, and when possible, the Partnership nets the open positions of each counterparty.

Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under its revolving credit facility. As of December 31, 2014, the Partnership had $1.5 billion of outstanding borrowings exposed to variable interest rate risk.

Credit Risk. The Partnership's resale of NGLs, condensate and natural gas exposes it to credit risk, as the margin on any sale is generally a very small percentage of the total sales price. Therefore, a credit loss can be very large relative to overall profitability on these transactions. The Partnership attempts to ensure that it issues credit only to credit-worthy counterparties and that in appropriate circumstances any such extension of credit is backed by adequate collateral, such as a letter of credit or parental guarantee from a parent company with potentially better credit.

The Partnership is exposed to credit risk from its derivative contract counterparties. The Partnership does not require collateral from these counterparties. The Partnership deals primarily with financial institutions when entering into financial derivatives, and utilizes master netting agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximum loss as of December 31, 2014 was $82 million, which would be reduced by less than $1 million due to the netting feature. The Partnership has elected to present assets and liabilities under master netting agreements gross on the consolidated balance sheets.

Embedded Derivatives. The Series A Preferred Units contain embedded derivatives which are required to be bifurcated and accounted for separately, such as the holders' conversion option and the Partnership's call option. These embedded derivatives are accounted for using mark-to-market accounting. The Partnership does not expect the embedded derivatives to affect its cash flows.

The Partnership's derivative assets and liabilities, including credit risk adjustments, as of December 31, 2014 and 2013 are detailed below:

	Assets		Liabilities	
	December 31,		December 31,	
	2014	2013	2014	2013
Derivatives not designated as cash flow hedges				
Current amounts				
Commodity contracts	$ 75	$ 3	$ —	$ 9
Long-term amounts				
Commodity contracts	10	1	—	—
Embedded derivatives in Series A Preferred Units	—	—	16	19
Total derivatives	$ 85	$ 4	$ 16	$ 28

The Partnership's statements of operations for the years ended December 31, 2014, 2013 and 2012 were impacted by derivative instruments activities as detailed below:

		Years Ended December 31,		
		2014	2013	2012
Derivatives in cash flow hedging relationships:		**Change in Value Recognized in AOCI on Derivatives (Effective Portion)**		
Commodity derivatives		$ —	$ —	$ (4)
Derivatives in cash flow hedging relationships:	**Location of Gain/(Loss) Recognized in Income**	**Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)**		
Commodity derivatives	Revenue	$ —	$ —	$ 6

		Years Ended December 31,		
		2014	2013	2012
Derivatives not designated in a hedging relationship:	**Location of Gain/(Loss) Recognized in Income**	**Amount of Gain/(Loss) from De-designation Amortized from AOCI into Income**		
Commodity derivatives	Revenue	$ —	$ —	$ (5)
Derivatives not designated in a hedging relationship:	**Location of Gain/(Loss) Recognized in Income**	**Amount of Gain/(Loss) Recognized in Income from Derivatives**		
Commodity derivatives	Revenue	$ 93	$ (9)	$ 16
Embedded derivatives	Other income & deductions	3	6	14
		$ 96	$ (3)	$ 30

8. LONG-TERM DEBT

Obligations in the form of senior notes and borrowings under the credit facilities are as follows:

	December 31, 2014	December 31, 2013
Senior notes	$ 5,089	$ 2,800
Revolving loans	1,504	510
Unamortized premiums and discounts	48	—
Long-term debt	$ 6,641	$ 3,310
Availability under revolving credit facility:		
Total credit facility limit	$ 2,000	$ 1,200
Revolving loans	(1,504)	(510)
Letters of credit	(23)	(14)
Total available	$ 473	$ 676

Long-term debt maturities as of December 31, 2014 for each of the next five years are as follows:

Year Ended December 31,	Amount
2015	$ —
2016	—
2017	—
2018	—
2019	2,003
Thereafter	4,590
Total *	$ 6,593

* Excludes a $67 million unamortized premium on the 2020 PVR Notes and the 2021 PVR Notes assumed by the Partnership and a $19 million unamortized discount on the combined 2022 Notes.

Revolving Credit Facility

In the years ended December 31, 2014, 2013 and 2012 the Partnership borrowed $3.86 billion, $1.83 billion and $1.56 billion, respectively, under its revolving credit facility; these borrowings were to fund capital expenditures and acquisitions. During the same periods, the Partnership repaid $3.48 billion, $1.52 billion and $1.70 billion, respectively, with proceeds from equity offerings and issuances of senior notes.

In February 2014, RGS entered into the First Amendment (the "First Amendment") to the Sixth Amended and Restated Credit Agreement (the “Credit Agreement”) to, among other things, expressly permit the pending PVR and Eagle Rock Midstream acquisitions, and to increase the commitment base to $1.5 billion and increase the uncommitted incremental facility to $500 million. The First Amendment allowed the Partnership to assume the legacy PVR senior notes that mature prior to the Credit Agreement.

In September 2014, RGS entered into the Second Amendment to the Credit Agreement to, among other things, increase the letter of credit sublimit from $50 million to $100 million, with none of the four individual issuing banks being required to issue letters of credit in excess of $25 million; increase in the general basket of permitted investments from $300 million to $500 million; add provisions permitting investments in ORS, affording it similar treatment to the Partnership’s existing joint ventures; and update various swap agreement provisions to conform to current market standards.

In November 2014, RGS entered into the Seventh Amended and Restated Credit Agreement (the "New Credit Agreement") to increase the commitment to $2 billion and extended the maturity date to November 25, 2019. The material differences between the Credit Agreement and the New Credit Agreement include:

- the addition of provisions permitting investments in Mi Vida JV affording it similar treatment to the Partnership’s existing joint ventures;
- an increase in certain permitted covenant baskets; and
- updates to various pricing terms and the permitted maximum total leverage ratio to reflect the Partnership’s growth.

In connection with the New Credit Agreement, the Partnership capitalized $5 million of net loan fees related to the amendments completed in the year ended December 31, 2014, which are being amortized over the remaining term.

In May 2013, RGS entered into the Credit Agreement to increase the commitment to $1.2 billion with a $300 million uncommitted incremental facility and extended the maturity date to May 21, 2018. The material differences between the Fifth Amended and Restated Credit Agreement and the Credit Agreement include:

- A 75 bps decrease in pricing, with an additional 50 bps decrease upon the achievement of an investment grade rating;
- No limitation on the maximum amount that the loan parties may invest in joint ventures existing on the date of the credit agreement so long as the Partnership is in pro forma compliance with the financial covenants;
- The addition of a “Restricted Subsidiary” structure such that certain designated subsidiaries are not subject to the credit facility covenants and do not guarantee the obligations thereunder or pledge their assets in support thereof;
- The addition of provisions such that upon the achievement of an investment grade rating by the Partnership, the collateral package will be released; the facility will become unsecured; and the covenant package will be significantly reduced;
- An eight-quarter increase in the permitted Total Leverage Ratio; and
- After March 2015, an increase in the permitted total leverage ratio for the two fiscal quarters following any $50 million or greater acquisition.

In connection with the Credit Agreement, the Partnership capitalized $6 million of net loan fees related to this amendment which are being amortized over the remaining term.

Borrowings under the New Credit Agreement are secured by substantially all of the Partnership’s assets and are guaranteed by the Partnership and its consolidated subsidiaries, except for ELG and ORS. The New Credit Agreement and the guarantees thereunder are senior to the Partnership’s and the guarantors’ unsecured obligations.

The outstanding balance under the New Credit Agreement bears interest at LIBOR plus a margin or alternate base rate (equivalent to the U.S. prime lending rate) plus a margin, or a combination of both. The alternate base rate used to calculate interest on base rate loans will be calculated based on the greatest to occur of a base rate, a federal funds effective rate plus 0.50% and an adjusted one-month LIBOR rate plus 1.00%. The applicable margin shall range from 0.50% to 1.25% for base rate loans, 1.50% to 2.25% for Eurodollar loans. The weighted average interest rate on the amounts outstanding under the Partnership’s Credit Agreement was 2.17% as of December 31, 2014 and 2013.

RGS must pay (i) a commitment fee ranging from 0.25% to 0.375% per annum of the unused portion of the revolving loan commitments, (ii) a participation fee for each revolving lender participating in letters of credit ranging from 1.5% to 2.25% per annum of the average daily amount of such lender’s letter of credit exposure and (iii) a fronting fee to the issuing bank of letters of credit equal to 0.20% per annum of the average daily amount of the letter of credit exposure. These fees are included in interest expense, net in the consolidated statement of operations.

The New Credit Agreement contains financial covenants requiring RGS and its subsidiaries to maintain a debt to consolidated EBITDA (as defined in the credit agreement) ratio less than 5.50, a consolidated EBITDA to consolidated interest expense ratio greater than 2.50 and a secured debt to consolidated EBITDA ratio less than 3.25. At December 31, 2014 and 2013, RGS and its subsidiaries were in compliance with these covenants.

The New Credit Agreement restricts the ability of RGS to pay dividends and distributions other than reimbursements to the Partnership for expenses and payment of dividends to the Partnership for the amount of available cash (as defined) so long as no default or event of default has occurred or is continuing. The New Credit Agreement also contains various covenants that limit (subject to certain exceptions), among other things, the ability of RGS to:

- incur indebtedness;
- grant liens;
- enter into sale and leaseback transactions;
- make certain investments, loans and advances;
- dissolve or enter into a merger or consolidation;
- enter into asset sales or make acquisitions;
- enter into transactions with affiliates;
- prepay other indebtedness or amend organizational documents or transactions documents (as defined in the New Credit Agreement);
- issue capital stock or create subsidiaries; or
- engage in any business other than those businesses in which it was engaged at the time of the effectiveness of the New Credit Agreement or reasonable extension thereof.

In February 2015, RGS exercised the accordion feature of the New Credit Agreement to increase commitments under the revolving credit facility by $500 million to a total of $2.5 billion. The increased commitments will be available pursuant to the same terms and subject to the same interest rates and fees as the existing commitments under the New Credit Agreement.

Senior Notes

The Partnership and Finance Corp. have the following series of senior notes (collectively “Senior Notes”):

- $400 million in aggregate principal amount of our 5.75% senior notes due September 1, 2020 (the “2020 Notes“) with interest payable semi-annually in arrears on March 1 and September 1;
- $500 million in aggregate principal amount of our 6.5% senior notes due July 15, 2021 (the “2021 Notes“) with interest payable semi-annually in arrears on January 15 and July 15;
- $900 million in aggregate principal of our 5.875% senior notes due March 1, 2022 (the “2022 Notes“), issued in February 2014, with interest payable semi-annually in arrears on March 1 and September 1;
- $700 million in aggregate principal amount of our 5.5% senior notes due April 15, 2023 (the “2023 5.5% Notes“) with interest payable semi-annually in arrears on April 15 and October 15;
- $600 million in aggregate principal amount of our 4.5% senior notes due November 1, 2023 (the “2023 4.5% Notes“) with interest payable semi-annually in arrears on May 1 and November 1;
- $390 million, after partial redemption, in aggregate principal amount of our 8.375% senior notes due June 1, 2020 (the “2020 PVR Notes“) with interest payable semi-annually in arrears on June 1 and December 1;
- $400 million in aggregate principal amount of our 6.5% senior notes due May 15, 2021 (the “2021 PVR Notes“) with interest payable semi-annually in arrears on May 15 and November 15;
- $499 million in aggregate principal amount of our 8.375% senior notes due June 1, 2019 (the “2019 Notes“) with interest payable semi-annually in arrears on June 1 and December 1; and
- $700 million in aggregate principal amount of our 5% senior notes due October 1, 2022 (the “October 2022 Notes“) with interest payable semi-annually in arrears on April 1 and October 1.

In May 2009, the Partnership and Finance Corp. issued $250 million of senior notes with a maturity of June 1, 2016 (the “2016 Notes”). The 2016 Notes bore interest at 9.375% with interest payable semi-annually in arrears on June 1 and December 1. In May 2012, the Partnership redeemed 35%, or $88 million, of the 2016 Notes, bringing the total outstanding principal amount to $163 million. A redemption premium of $8 million was charged to loss on debt refinancing, net in the consolidated statements of operations and $4 million of accrued interest was paid. The Partnership also wrote off the unamortized loan fee of $1 million and unamortized bond premium of $2 million to loss on debt refinancing, net in the consolidated statement of operations. In June 2013, the Partnership redeemed all amounts outstanding 2016 Notes for $178 million cash, inclusive of accrued and unpaid interest of $7 million and other fees and expenses.

In February 2014, the Partnership and Finance Corp. issued $900 million of senior notes that mature on March 1, 2022 (the “2022 Notes”). The 2022 Notes bear interest at 5.875% with interest payable semi-annually in arrears on September 1 and March 1. At any time prior to December 1, 2021, the Partnership may redeem some or all of the notes at 100% of the principal amount thereof, plus a “make-whole” redemption price and accrued and unpaid interest, if any, to the redemption date. On or after December 1, 2021, the Partnership may redeem some or all of the 2022 Notes at a redemption price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date. The 2022 Notes rank equally with the Partnership’s other Senior Notes.

In March 2014, in connection with the PVR Acquisition, the Partnership assumed $1.2 billion in aggregate principal amount of PVR’s outstanding senior notes, consisting of $300 million of 8.25% senior notes that mature on April 15, 2018 (the “2018 PVR Notes”), $400 million of 6.5% senior notes that mature on May 15, 2021 (the “2021 PVR Notes”), and $473 million of 8.375% senior notes that mature on June 1, 2020 (the “2020 PVR Notes”, and together with the 2021 PVR Notes, the "PVR Notes"). In April 2014, the Partnership redeemed all of the 2018 PVR Notes for $313 million at a price of 104.125% plus accrued and unpaid interest paid to the redemption date. Interest on the 2021 PVR Notes and the 2020 PVR Notes accrue semi-annually on May 15 and November 15 and June 1 and December 1, respectively. The PVR Notes rank equally with the Partnership’s other Senior Notes.

On March 24, 2014, in accordance with the Partnership’s obligations under the indentures governing the PVR Notes, the Partnership commenced change of control offers pursuant to which holders of such notes were entitled to require the Partnership to repurchase all or a portion of its PVR Notes at a purchase price of 101% of the principal amount thereof, plus accrued and unpaid interest to the repurchase date. The change of control offers for the PVR Notes expired on April 22, 2014 and, on April 23, 2014, the Partnership accepted for purchase less than $1 million in aggregate principal amount of 2021 PVR Notes.

In July 2014, in connection with the Eagle Rock Midstream Acquisition, the Partnership exchanged $499 million of 8.375% Senior Notes due 2019 of Eagle Rock and Eagle Rock Energy Finance Corp. for 8.375% Senior Notes due 2019 issued by the Partnership and Finance Corp. (the “New Partnership Notes”). The New Partnership Notes rank equally with the Partnership’s other Senior Notes.

In July 2014, the Partnership and Finance Corp. issued $700 million of senior notes that mature on October 1, 2022 (the “October 2022 Notes”). The October 2022 Notes bear interest at 5% with interest payable semi-annual in arrears on October 1 and April 1, beginning April 1, 2015. At any time prior to July 1, 2022, the Partnership may redeem some or all of the October 2022 Notes at 100% of the principal amount thereof, plus a “make-whole” redemption price and accrued and unpaid interest, if any, to the redemption date. On or after, July 1, 2022, the Partnership may redeem some or all of the October 2022 Notes at a redemption price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date. The October 2022 Notes rank equally with the Partnership’s other Senior Notes.

In July 2014, the Partnership redeemed $83 million of the $473 million outstanding 2020 PVR Notes for $91 million, including $8 million of accrued interest and redemption premium.

In December 2014, the Partnership redeemed all of the outstanding $600 million 2018 Notes, for a total price of 103.438% or $621 million.

The Senior Notes issued by the Partnership and Finance Corp. are fully and unconditionally guaranteed, on a joint and several basis, by all of the Partnership’s consolidated subsidiaries, except for ELG and ORS.

The Senior Notes are redeemable at any time prior to the dates specified below at a price equal to 100% of the principal amount of the applicable series, plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date:

- 2020 Notes - Redeemable, in whole or in part, prior to June 1, 2020 at 100% of the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or after June 1, 2020 at 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date
- 2021 Notes - Any time prior to July 15, 2014, up to 35% may be redeemed at a price of 106.5% plus accrued and unpaid interest, if any; beginning July 15, 2016, 100% may be redeemed at fixed redemption price of 103.25% (July 15, 2017 - 102.167%, July 15, 2018 - 101.083% and July 15, 2019 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2022 Notes - Redeemable, in whole or in part, prior to December 1, 2021 at 100% at the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or after December 1, 2021 at 100% at the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date
- 2023 5.5% Notes - Any time prior to October 15, 2015, up to 35% may be redeemed at a price of 105.5% plus accrued and unpaid interest, if any; beginning October 15, 2017, 100% may be redeemed at fixed redemption price of 102.75% (October 15, 2018 - 101.833%, October 15, 2019 - 100.917% and October 15, 2020 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2023 4.5% Notes - Redeemable, in whole or in part, prior to August 1, 2023 at 100% of the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or after August 1, 2023 at 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date
- 2020 PVR Notes - Any time prior to June 1, 2015, up to 35% may be redeemed at a price of 108.375% plus accrued and unpaid interest, if any; beginning June 1, 2016, 100% may be redeemed at fixed redemption price of 104.188% (June 1, 2017 - 102.094%, June 1, 2018 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2021 PVR Notes - Any time prior to May 15, 2016, up to 35% may be redeemed at a price of 106.5% plus accrued and unpaid interest and liquidated damages, if any; beginning May 15, 2016, 100% may be redeemed at a fixed redemption price of 104.875% (May 15, 2017 - 103.250%, May 15, 2018 - 101.625% and May 15, 2019 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- 2019 Notes - Redeemable, in whole or in part, prior to June 1, 2015 at 100% at the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; beginning June 1, 2015, 100% may be redeemed at a fixed redemption price of 104.188% (June 1, 2016 - 102.094% and June 1, 2017 and thereafter - 100%) plus accrued and unpaid interest, if any, to the redemption date
- October 2022 Notes - Redeemable, in whole or in part, prior to July 1, 2022 at 100% of the principal amount plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date; redeemable, in whole or in part, on or

after July 1, 2022 at 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date

Upon a change of control followed by a ratings downgrade within 90 days of a change of control, each holder of the Partnership's Senior Notes, other than the PVR Notes, will be entitled to require the Partnership to repurchase all or a portion of its notes at a purchase price of 101% plus accrued and unpaid interest, if any. Upon a change of control, the indenture governing the PVR Notes requires the Partnership to make an offer to repurchase all outstanding notes at 101% of the principal amount thereof, plus accrued and unpaid interest (and additional interest, if any) to the date of repurchase. The Partnership's ability to repurchase the Senior Notes upon a change of control will be limited by the terms of our debt agreements, including the Partnership's revolving credit facility.

The Senior Notes contain various covenants that limit, among other things, the Partnership's ability, and the ability of certain of the Partnership's subsidiaries, to:

- incur additional indebtedness;
- pay distributions on, or repurchase or redeem our equity interests;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets or consolidate or merge with or into other companies.

If the Senior Notes achieve investment grade ratings by both Moody's and Standard & Poor's and no default or event of default has occurred and is continuing, the Partnership will no longer be subject to many of the foregoing covenants. At December 31, 2014, the Partnership was in compliance with these covenants.

9. INTANGIBLE ASSETS

Activity related to intangible assets, net consisted of the following:

	Customer Relations	Trade Names	Total
Balance at January 1, 2013	$ 655	$ 57	$ 712
Amortization	(26)	(4)	(30)
Balance at December 31, 2013	629	53	682
Amortization	(105)	(3)	(108)
Intangible assets acquired	2,865	—	2,865
Balance at December 31, 2014	$ 3,389	$ 50	$ 3,439

The average remaining amortization periods for customer relations and trade names are 28 and 15 years, respectively. The expected amortization of the intangible assets for each of the five succeeding years is $135 million.

10. FAIR VALUE MEASURES

The fair value measurement provisions establish a three-tiered fair value hierarchy that prioritizes inputs to valuation techniques used in fair value calculations. The three levels of inputs are defined as follows:

- Level 1—unadjusted quoted prices for identical assets or liabilities in active accessible markets;
- Level 2—inputs that are observable in the marketplace other than those classified as Level 1; and
- Level 3—inputs that are unobservable in the marketplace and significant to the valuation.

Entities are encouraged to maximize the use of observable inputs and minimize the use of unobservable inputs. If a financial instrument uses inputs that fall in different levels of the hierarchy, the instrument will be categorized based upon the lowest level of input that is significant to the fair value calculation.

The Partnership's financial assets and liabilities measured at fair value on a recurring basis are derivatives related to commodity swaps and embedded derivatives in the Series A Preferred Units. Derivatives related to commodity swaps are valued using discounted cash flow techniques. These techniques incorporate Level 1 and Level 2 inputs such as commodity prices. These market inputs are utilized in the discounted cash flow calculation considering the instrument's term, notional amount, discount rate and credit risk and are classified as Level 2 in the hierarchy. Embedded derivatives related to Series A Preferred Units are valued using a binomial lattice model. The inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, common unit price, dividend yield, and expected volatility, and are classified as Level 3 in the hierarchy.

The following table presents the Partnership's derivative assets and liabilities measured at fair value on a recurring basis:

	Fair Value Measurement at December 31,					
	2014			2013		
	Fair Value Total	Level 2	Level 3	Fair Value Total	Level 2	Level 3
Assets						
Commodity Derivatives:						
Natural Gas	$ 26	$ 26	$ —	$ 2	$ 2	$ —
Natural Gas Liquids	23	23	—	2	2	—
Condensate	36	36	—	—	—	—
Total Assets	$ 85	$ 85	$ —	$ 4	$ 4	$ —
Liabilities						
Commodity Derivatives:						
Natural Gas	$ —	$ —	$ —	$ 4	$ 4	$ —
Natural Gas Liquids	—	—	—	4	4	—
Condensate	—	—	—	1	1	—
Embedded Derivatives in Series A Preferred Units	16	—	16	19	—	19
Total Liabilities	$ 16	$ —	$ 16	$ 28	$ 9	$ 19

The following table presents the material unobservable inputs used to estimate the fair value of the embedded derivatives in the Series A Preferred Units:

Unobservable Input	December 31, 2014
Credit Spread	4.76%
Volatility	35.8%

Changes in the Partnership's cost of equity and U.S. Treasury yields would cause a change in the credit spread used to value the embedded derivatives.

The following table presents the changes in Level 3 derivatives measured on a recurring basis for the years ended December 31, 2014 and 2013. There were no transfers between Level 2 and Level 3 derivatives for the years ended December 31, 2014 and 2013.

	Embedded Derivatives in Series A Preferred Units
Balance at January 1, 2013	$ 25
Change in fair value, net of gain at conversion of $26 million	(6)
Balance at December 31, 2013	19
Change in fair value	(3)
Balance at December 31, 2014	$ 16

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. Long-term debt, other than the Senior Notes, is comprised of borrowings under which interest accrues under a floating interest rate structure. Accordingly, the carrying value approximates fair value.

The aggregate fair value and carrying amount of the Senior Notes at December 31, 2014 and 2013 was $5.1 billion and $2.8 billion, respectively. The fair value of the Senior Notes is a Level 1 valuation based on third party market value quotations.

11. LEASES

The following table is a schedule of future minimum lease payments for office space and certain equipment leased by the Partnership, that had initial or remaining non-cancelable lease terms in excess of one year as of December 31, 2014:

For the year ending December 31,	Operating Lease
2015	$ 5
2016	5
2017	4
2018	3
2019	2
Thereafter	26
Total minimum lease payments	$ 45

Total rent expense for operating leases, including those leases with terms of less than one year, was $20 million, $11 million and $11 million for the years ended December 31, 2014, 2013 and 2012, respectively.

12. COMMITMENTS AND CONTINGENCIES

Legal. The Partnership is involved in various claims, lawsuits and audits by taxing authorities incidental to its business. These claims and lawsuits in the aggregate are not expected to have a material adverse effect on the Partnership's business, financial condition, results of operations or cash flows.

ETP Merger Shareholder Litigation. Following the January 26, 2015 announcement of the definitive merger agreement with ETP, purported Partnership unitholders filed lawsuits in state and federal courts in Dallas, Texas asserting claims relating to the proposed transaction.

On February 3, 2015, William Engel and Enno Seago, purported Partnership unitholders, filed a class action petition on behalf of the Partnership's common unitholders and a derivative suit on behalf of the Partnership in the 162nd Judicial District Court of Dallas County, Texas (the "Engel Lawsuit"). The lawsuit names as defendants the General Partner, the members of the General Partner's board of directors, ETP, ETP GP, ETE, and, as a nominal party, the Partnership. The Engel Lawsuit alleges that (1) the General Partner's directors breached duties to the Partnership and the Partnership's unitholders by employing a conflicted and unfair process and failing to maximize the merger consideration; (2) the General Partner's directors breached the implied covenant of good faith and fair dealing by engaging in a flawed merger process; and (3) the non-director defendants aided and abetted in these claimed breaches. The plaintiffs seek an injunction preventing the defendants from closing the proposed transaction or an order rescinding the transaction if it has already been completed. The plaintiffs also seek money damages and court costs, including attorney's fees.

On February 9, 2015, Stuart Yeager, a purported Partnership unitholder, filed a class action petition on behalf of the Partnership's common unitholders and a derivative suit on behalf of the Partnership in the 134th Judicial District Court of Dallas County, Texas (the "Yeager Lawsuit"). The allegations, claims, and relief sought in the Yeager Lawsuit are nearly identical to those in the Engel Lawsuit.

On February 10, 2015, Lucien Coggia a purported Partnership unitholder, filed a class action petition on behalf of the Partnership's common unitholders and a derivative suit on behalf of the Partnership in the 192nd Judicial District Court of Dallas County, Texas (the "Coggia Lawsuit"). The allegations, claims, and relief sought in the Coggia Lawsuit are nearly identical to those in the Engel Lawsuit.

On February 3, 2015, Linda Blankman, a purported Partnership unitholder, filed a class action complaint on behalf of the Partnership's common unitholders in the United States District Court for the Northern District of Texas (the "Blankman Lawsuit"). The allegations and claims in the Blankman Lawsuit are similar to those in the Engel Lawsuit. However, the Blankman Lawsuit does not allege any derivative claims and includes the Partnership as a defendant rather than a nominal party. The lawsuit also omits one of the General Partner's directors, Richard Brannon, who was named in the Engel Lawsuit. The Blankman Lawsuit alleges that the General Partner's directors breached their fiduciary duties to the unitholders by failing to maximize the value of the Partnership, failing to properly value the Partnership, and ignoring conflicts of interest. The plaintiff also asserts a claim against the non-director defendants for aiding and abetting the directors' alleged breach of fiduciary duty. The Blankman Lawsuit seeks the same relief that the plaintiffs seek in the Engel Lawsuit.

On February 6, 2015, Edwin Bazini, a purported Partnership unitholder, filed a class action complaint on behalf of the Partnership's common unitholders in the United States District Court for the Northern District of Texas (the "Bazini Lawsuit"). The allegations, claims, and relief sought in the Bazini Lawsuit are nearly identical to those in the Blankman Lawsuit.

On February 11, 2015, Mark Hinnau, a purported Partnership unitholder, filed a class action complaint on behalf of the Partnership's common unitholders in the United States District Court for the Northern District of Texas (the "Hinnau Lawsuit"). The allegations, claims, and relief sought in the Hinnau Lawsuit are nearly identical to those in the Blankman Lawsuit.

On February 11, 2015, Stephen Weaver, a purported Partnership unitholder, filed a class action complaint on behalf of the Partnership's common unitholders in the United States District Court for the Northern District of Texas (the "Weaver Lawsuit"). The allegations, claims, and relief sought in the Weaver Lawsuit are nearly identical to those in the Blankman Lawsuit.

On February 11, 2015, Adrian Dieckman, a purported Partnership unitholder, filed a class action complaint on behalf of the Partnership's common unitholders in the United States District Court for the Northern District of Texas (the "Dieckman Lawsuit"). The allegations, claims, and relief sought in the Dieckman Lawsuit are similar to those in the Blankman Lawsuit, except that the Dieckman Lawsuit does not assert an aiding and abetting claim.

On February 13, 2015, Irwin Berlin, a purported Partnership unitholder, filed a class action complaint on behalf of the Partnership's common unitholders in the United States District Court for the Northern District of Texas (the "Dieckman Lawsuit"). The allegations, claims, and relief sought in the Berlin Lawsuit are similar to those in the Blankman Lawsuit.

Each of these lawsuits is at a preliminary stage. We cannot predict the outcome of these or any other lawsuits that might be filed, nor can we predict the amount of time and expense that will be required to resolve these lawsuits. The Partnership and the other defendants named in the lawsuits intend to defend vigorously against these and any other actions.

PVR Shareholder Litigation. Five putative class action lawsuits challenging the PVR Acquisition are currently pending. All of the cases name PVR, PVR GP and the then-incumbent directors of PVR GP, as well as the Partnership and the General Partner (collectively, the "Regency Defendants"), as defendants. Each of the lawsuits has been brought by a purported unitholder of PVR, both individually and on behalf of a putative class consisting of public unitholders of PVR. The lawsuits generally allege, among other things, that the directors of PVR GP breached their fiduciary duties to unitholders of PVR, that PVR GP, PVR and the Regency Defendants aided and abetted the directors of PVR GP in the alleged breach of these fiduciary duties, and, as to the actions in federal court, that some or all of PVR, PVR GP, and the directors of PVR GP violated Section 14(a) of the Exchange Act and Rule 14a-9 promulgated thereunder and Section 20(a) of the Exchange Act. The lawsuits purport to seek, in general, (i) injunctive relief, (ii) disclosure of certain additional information concerning the transaction, (iii) rescission or an award of rescissory damages, (iv) an award of plaintiffs' costs and (v) the accounting for damages allegedly causes by the defendants to these actions, and, (vi) such further relief as the court deems just and proper. The styles of the pending cases are as follows: David Naiditch v. PVR Partners, L.P., et al. in the Court of Chancery of the State of Delaware); Charles Monatt v. PVR Partners, LP, et al. and Saul Srour v. PVR Partners, L.P., et al., each pending in the Court of Common Pleas for Delaware County, Pennsylvania; Stephen Bushansky v. PVR Partners, L.P., et al.; and Mark Hinnau v. PVR Partners, L.P., et al., pending in the United States District Court for the Eastern District of Pennsylvania.

On January 28, 2014, the defendants entered into a Memorandum of Understanding ("MOU") with Monatt, Srour, Bushansky, Naiditch and Hinnau pursuant to which defendants and the referenced plaintiffs agreed in principle to a settlement of their lawsuits ("Settled Lawsuits"), which will be memorialized in a separate settlement agreement, subject to customary conditions, including consummation of the PVR Acquisition, which occurred on March 21, 2014, completion of certain confirmatory discovery (which was completed as of September 5, 2014), class certification and final approval by the Court of Common Pleas for Delaware County, Pennsylvania. If the Court approves the settlement, the Settled Lawsuits will be dismissed with prejudice and all defendants will be released from any and all claims relating to the Settled Lawsuits.

The settlement did not affect any provisions of the merger agreement or the form or amount of consideration received by PVR unitholders in the PVR Acquisition. The defendants have denied and continue to deny any wrongdoing or liability with respect to the plaintiffs' claims in the aforementioned litigation and have entered into the settlement to eliminate the uncertainty, burden, risk, expense, and distraction of further litigation.

Eagle Rock Shareholder Litigation. Three putative class action lawsuits challenging the Eagle Rock Midstream Acquisition were previously filed in federal district court in Houston, Texas. All cases name Eagle Rock and its current directors, as well as the Partnership and a subsidiary, as defendants. One of the lawsuits also names additional Eagle Rock entities as defendants. Each of the lawsuits has been brought by a purported unitholder of Eagle Rock (collectively, the "Plaintiffs"), both individually and on behalf of a putative class consisting of public unitholders of Eagle Rock. The Plaintiffs in each case seek to rescind the transaction, claiming, among other things, that it yields inadequate consideration, was tainted by conflict and constitutes breaches of common law fiduciary duties or contractually imposed duties to the shareholders. Plaintiffs also seek monetary damages and attorneys' fees. The Partnership and its subsidiary are named as "aiders and abettors" of the allegedly wrongful actions of Eagle Rock and its board. In November 2014, the US District Court issued a Notice of Voluntary Dismissal without Prejudice of all claims in this matter.

PADEP Consent Assessment. On November 21, 2014, our subsidiary, Regency Marcellus Gas Gathering LLC ("Regency Marcellus"), received a Notice of Violation ("NOV") from the Pennsylvania Department of Environmental Protection ("PADEP") relating to unpermitted wetlands and streams along the second phase of construction of the Canton Pipeline Project with proposed civil penalties potentially in excess of $100,000. Regency Marcellus has submitted amended permit applications for this phase of construction and is working with the PADEP to acquire amended permits for the proposed crossings of the wetland resources. Regency Marcellus is in discussions with the PADEP regarding the aforementioned NOV. The timing or outcome of this matter cannot reasonably be determined at this time, however we do not expect there to be a material impact on our business or results of operations.

CDM Sales Tax Audit. CDM Resource Management LLC ("CDM"), a subsidiary of the Partnership, has historically claimed the manufacturing exemption from sales tax in Texas, as is common in the industry. The exemption is based on the fact that CDM's natural gas compression equipment is used in the process of treating natural gas for ultimate use and sale. In a recent audit by the Texas Comptroller's office, the Comptroller has challenged the applicability of the manufacturing exemption to CDM. The period being audited is from August 2006 to August 2007, and liability for that period is potentially covered by an indemnity obligation from CDM's prior owners. CDM may also have liability for periods since 2008, and prospectively, if the Comptroller's challenge is ultimately successful. An audit of the 2008 period has commenced. In April 2013, an independent audit review agreed with the Comptroller's position. While CDM continues to disagree with this position and intends to seek redetermination and other relief, we are unable to predict the final outcome of this matter.

Environmental. The Partnership is responsible for environmental remediation at certain sites on its gathering and processing systems, resulting primarily from releases of hydrocarbons. The Partnership's remediation program typically involves the management of contaminated soils and may involve remediation of groundwater. Activities vary with site conditions and locations, the extent and nature of the contamination, remedial requirements and complexity. The ultimate liability and total costs associated with these sites will depend upon many factors. In addition, the Partnership has reclamation and bonding requirements with respect to certain un-leased and inactive coal properties.

The table below reflects the undiscounted environmental liabilities recorded in the consolidated balance sheet at December 31, 2014 and 2013 where management believes a loss is probable and reasonably estimable. The Partnership does not have any material environmental remediation matters assessed as reasonably possible that would require disclosure in the financial statements.

	December 31,	
	2014	**2013**
Current	$ 2	$ 2
Noncurrent	8	6
Total environmental liabilities	$ 10	$ 8

The Partnership made expenditures related to environmental remediation of $2 million for the year ended December 31, 2014.

Air Quality Control. The Partnership is currently negotiating settlements to certain enforcement actions by the NMED and the TCEQ. The TCEQ recently initiated a state-wide emissions inventory for the sulfur dioxide emissions from sites with reported emissions of 10 tons per year or more. If this data demonstrates that any source or group of sources may cause or contribute to a violation of the National Ambient Air Quality Standards, they must be sufficiently controlled to ensure timely attainment of the standard. This may potentially affect three recovery units in Texas. It is unclear at this time how the NMED will address the sulfur dioxide standard.

Compliance Orders from the NMED. The Partnership has been in discussions with the NMED concerning allegations of violations of New Mexico air regulations related to the Jal #3 and Jal #4 facilities. Hearings on the compliance orders were delayed until May 2015 to allow the parties to pursue substantive settlement discussions. The Partnership has meritorious defenses to the NMED claims and can offer significant mitigating factors to the claimed violations. The Partnership has recorded a liability of less than $1 million related to the claims and will continue to assess its potential exposure to the allegations as the matters progress.

Mine Health and Safety Laws. There are numerous mine health and safety laws and regulations applicable to the coal mining industry. However, since the Partnership does not operate any mines and does not employ any coal miners, it is not subject to such laws and regulations. Accordingly, the Partnership has not accrued any related liabilities.

In addition to the matters discussed above, the Partnership is involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business.

13. SERIES A PREFERRED UNITS

On September 2, 2009, the Partnership issued 4,371,586 Series A Preferred Units for net proceeds of $79 million, inclusive of the General Partner's contribution of $2 million.

Holders may elect to convert Series A Preferred Units to common units at any time. In July 2013, certain holders of Series A Preferred Units exercised their right to convert 2,459,017 Series A Preferred Units into common units. Concurrent with this transaction, the Partnership recognized a $26 million gain in other income and deductions, net, related to the embedded derivative and reclassified $41 million from the Series A Preferred Units into common units. As of December 31, 2014, the remaining Series A Preferred Units were convertible into 2,064,805 common units, and if outstanding, are mandatorily redeemable on September 2, 2029 for $35 million plus all accrued but unpaid distributions and interest thereon (the "Series A Liquidation Value"). The Series A Preferred Units receive fixed quarterly cash distributions of $0.445 per unit if outstanding on the record dates of the Partnership's common unit distributions.

Distributions on the Series A Preferred Units were accrued for the first two quarters (and not paid in cash) and will result in an increase in the number of common units issuable upon conversion. If on any distribution payment date beginning March 31, 2010, the Partnership (1) fails to pay distributions on the Series A Preferred Units, (2) reduces the distributions on the common units to zero and (3) is prohibited by its material financing agreements from paying cash distributions, such distributions shall automatically accrue and accumulate until paid in cash. If the Partnership has failed to pay cash distributions in full for two quarters (whether or not consecutive) from and including the quarter ended on March 31, 2010, then if the Partnership fails to pay cash distributions on the Series A Preferred Units, all future distributions on the Series A Preferred Units that are accrued rather than being paid in cash by the Partnership will consist of the following: (1) $0.35375 per Series A Preferred Unit per quarter, (2) $0.09125 per Series A Preferred Unit per quarter (the "Common Unit Distribution Amount"), payable solely in common units, and (3) $0.09125 per Series A Preferred Unit per quarter (the "PIK Distribution Additional Amount"), payable solely in common units. The total number of common units payable in connection with the Common Unit Distribution Amount or the PIK Distribution Additional Amount cannot exceed $2 million in any period of 20 consecutive fiscal quarters.

Upon the Partnership's breach of certain covenants (a "Covenant Default"), the holders of the Series A Preferred Units will be entitled to an increase of $0.1825 per quarterly distribution, payable solely in common units (the "Covenant Default Additional Amount"). All accumulated and unpaid distributions will accrue interest (i) at a rate of 2.432% per quarter, or (ii) if the Partnership has failed to pay all PIK Distribution Additional Amounts or Covenant Default Additional Amounts or any Covenant Default has occurred and is continuing, at a rate of 3.429% per quarter while such failure to pay or such Covenant Default continues.

The Series A Preferred Units are convertible, at the holder's option, into common units, provided that the holder must request conversion of at least 375,000 Series A Preferred Units. The conversion price will initially be $18.30, subject to adjustment for customary events (such as unit splits). The number of common units issuable is equal to the issue price of the Series A Preferred Units (i.e. $18.30) being converted plus all accrued but unpaid distributions and accrued but unpaid interest thereon (the "Redeemable Face Amount"), divided by the applicable conversion price.

If at any time the volume-weighted average trading price of the common units over the trailing 20-trading day period (the "VWAP Price") is less than the then-applicable conversion price, the conversion ratio is increased to: the quotient of (1) the Redeemable Face Amount on the date that the holder's conversion notice is delivered, divided by (2) the product of (x) the VWAP Price set forth in the applicable conversion notice and (y) 91%, but will not be less than $10.

The Partnership has the right at any time to convert all or part of the Series A Preferred Units into common units, if (1) the daily volume-weighted average trading price of the common units is greater than 150% of the then-applicable conversion price for 20 out of the trailing 30 trading days, and (2) certain minimum public float and trading volume requirements are satisfied.

In the event of a change of control, the Partnership will be required to make an offer to the holders of the Series A Preferred Units to purchase their Series A Preferred Units for an amount equal to 101% of their Series A Liquidation Value. In addition, in the event of certain business combinations or other transactions involving the Partnership in which the holders of common units receive cash consideration exclusively in exchange for their common units (a "Cash Event"), the Partnership must use commercially reasonable efforts to ensure that the holders of the Series A Preferred Units will be entitled to receive a security issued by the surviving entity in the Cash Event with comparable powers, preferences and rights to the Series A Preferred Units. If the Partnership is unable to ensure that the holders of the Series A Preferred Units will be entitled to receive such a security, then the Partnership will be required to make an offer to the holders of the Series A Preferred Units to purchase their Series A Preferred Units for an amount equal to 120% of their Series A Liquidation Value. If the Partnership enters into any recapitalization, reorganization, consolidation, merger, spin-off that is not a Cash Event, the Partnership will make appropriate provisions to ensure that the holders of the Series A Preferred Units receive a security with comparable powers, preferences and rights to the Series A Preferred Units upon consummation of such transaction. Subsequent to the ETE Acquisition, no unitholder exercised this option.

As of December 31, 2014, the Series A Preferred Units were convertible to 2,064,805 common units.

The following table provides a reconciliation of the beginning and ending balances of the Series A Preferred Units for the years ended December 31, 2014 and 2013:

	Units	Amount
Balance at January 1, 2013	4,371,586	$ 73
Series A Preferred Units converted to common units	(2,459,017)	(41)
Balance at January 1, 2014	1,912,569	32
Accretion to redemption value	N/A	1
Balance at December 31, 2014	1,912,569	$ 33 *

* This amount will be accreted to $35 million plus any accrued but unpaid distributions and interest by deducting amounts from partners' capital over the remaining periods until the mandatory redemption date of September 2, 2029. Accretion during 2013 was immaterial.

14. RELATED PARTY TRANSACTIONS

As of December 31, 2014 and 2013, details of the Partnership's related party receivables and related party payables were as follows:

	December 31, 2014	December 31, 2013
Related party receivables		
ETE and its subsidiaries	43	25
HPC	1	1
Ranch JV	1	2
Total related party receivables	$ 45	$ 28
Related party payables		
ETE and its subsidiaries	50	68
HPC	3	1
Mi Vida JV	11	—
Total related party payables	$ 64	$ 69

Transactions with ETE and its subsidiaries. Under the service agreement with Services Co., the Partnership paid Services Co.'s direct expenses for services performed, plus an annual fee of $10 million, and received the benefit of any cost savings recognized for these services. The services agreement has a five year term ending May 26, 2015, subject to earlier termination rights in the event of a change in control, the failure to achieve certain cost savings for the Partnership or upon an event of default. On April 30, 2013, this agreement was amended to provide for a waiver of the $10 million annual fee effective as of May 1, 2013 through and including April 30, 2015 and to clarify the scope and expenses chargeable as direct expenses thereunder.

On April 30, 2013, the Partnership entered into the second amendment (the "Operation and Service Amendment") to the Operation and Service Agreement (the "Operation and Service Agreement"), by and among the Partnership, ETC, the General Partner and RGS. Under the Operation and Service Agreement, ETC performs certain operations, maintenance and related services reasonably required to operate and maintain certain facilities owned by the Partnership, and the Partnership reimburses ETC for actual costs and expenses incurred in connection with the provision of these services based on an annual budget agreed upon by both parties.

The Partnership incurred total service fees related to the agreements described above from ETE and its subsidiaries of $6 million, $11 million and $17 million for the years ended December 31, 2014, 2013 and 2012, respectively.

In conjunction with distributions made by the Partnership to the limited and general partner interests, ETE and its subsidiaries received cash distributions of $175 million, $107 million and $62 million for the years ended December 31, 2014, 2013 and 2012, respectively.

The General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership to maintain its general partner interest. No capital contributions were contributed during the years ended December 31, 2014 and 2013.

The Partnership’s Gathering and Processing segment, in the ordinary course of business, sells natural gas and NGLs to subsidiaries of ETE and records the revenue in gas sales and NGL sales. The Partnership’s Contract Services segment provides contract compression services to a subsidiary of ETE and records revenue in gathering, transportation and other fees on the statement of operations. As these transactions are between entities under common control, partners’ capital was increased, which represented a deemed contribution of the excess sales price over the carrying amounts. The Partnership’s Gathering and Processing segment recorded revenues from subsidiaries of ETE of $351 million and cost of sales to subsidiaries of ETE of $52 million for the year ended December 31, 2014. The Partnership’s Contract Services segment recorded revenues from a subsidiary of ETE of $1 million for the year ended December 31, 2014. The Partnership’s Contract Services segment purchased $67 million and $95 million of compression equipment from a subsidiary of ETE during the years ended December 31, 2014 and 2013, respectively.

Prior to April 30, 2013, Southern Union provided certain administrative services for SUGS that were either based on SUGS’s pro-rata share of combined net investment, margin and certain expenses or direct costs incurred by Southern Union on the behalf of SUGS. Southern Union also charged a management and royalty fee to SUGS for certain management support services provided by Southern Union on the behalf of SUGS and for the use of certain Southern Union trademarks, trade names and service marks by SUGS. The amounts were $21 million and $1 million for the period from March 26, 2012 to December 31, 2012. These administrative services were no longer being provided subsequent to the SUGS Acquisition.

Transactions with Lone Star. The Partnership entered into various agreements to sell NGLs to Lone Star. For the year ended December 31, 2014, the Partnership had recorded $257 million in NGL sales under these contracts.

Transactions with HPC. Under a Master Services Agreement with HPC, the Partnership operates and provides all employees and services for the operation and management of HPC. For the years ended December 31, 2014, 2013, and 2012, the related party general and administrative expenses reimbursed to the Partnership were $14 million, $18 million, and $20 million, respectively, which is recorded in gathering, transportation and other fees.

The Partnership’s Contract Services segment provides compression services to HPC and records revenue in gathering, transportation and other fees. The Partnership also receives transportation services from HPC and records it as cost of sales.

15. CONCENTRATION RISK

The following table provides information about the extent of reliance on major customers and gas suppliers. Total revenues and cost of sales from transactions with an external customer or supplier amounting to 10% or more of revenue or cost of gas and liquids are disclosed below, together with the identity of the reportable segment.

		Years Ended December 31,		
	Reportable Segment	**2014**	**2013**	**2012**
Customer				
Customer A	Gathering and Processing	$ —	$ 381	$ 367
Customer B	Gathering and Processing	780	362	451
Supplier				
Supplier A	Gathering and Processing	—	164	171
Supplier B	Gathering and Processing	—	185	—

The Partnership is a party to various commercial netting agreements that allow it and contractual counterparties to net receivable and payable obligations. These agreements are customary and the terms follow standard industry practice. In the opinion of management, these agreements reduce the overall counterparty risk exposure.

16. SEGMENT INFORMATION

The Partnership has six reportable segments: Gathering and Processing, Natural Gas Transportation, NGL Services, Contract Services, Natural Resources and Corporate. The reportable segments are as described below:

- *Gathering and Processing.* The Partnership provides “wellhead-to-market” services to producers of natural gas, which include transporting raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate NGLs from the raw natural gas and selling or delivering pipeline-quality natural gas and NGLs to various markets and pipeline systems, the gathering of oil (crude and/or condensate, a lighter oil) received from producers, the gathering and disposing of salt water, and natural gas and NGL marketing and trading. This segment also includes the Partnership’s 60% membership interest in ELG, which operates natural gas gathering, oil pipeline, and oil stabilization facilities in south Texas, the Partnership’s 33.33% membership interest in Ranch JV, which processes natural gas delivered from NGL-rich shale formations in west Texas, the Partnership’s 50% interest in Sweeny JV, which operates a natural gas gathering facility in south Texas, the Partnership’s 51% membership interest in Aqua - PVR, which transports and supplies fresh water to natural gas producers in the Marcellus shale in Pennsylvania, the Partnership’s 75% membership interest in ORS, which will operate a natural gas gathering system in the Utica shale in Ohio, and the Partnership’s 50% interest in Mi Vida JV, which will operate a cryogenic processing plant and related facilities in west Texas.
- *Natural Gas Transportation.* The Partnership owns a 49.99% general partner interest in HPC, which owns RIGS, a 450-mile intrastate pipeline that delivers natural gas from northwest Louisiana to downstream pipelines and markets, and a 50% membership interest in MEP, which owns a 500-mile interstate natural gas pipeline stretching from southeast Oklahoma through northeast Texas, northern Louisiana and central Mississippi to an interconnect with the Transcontinental Gas Pipe Line system in Butler, Alabama. This segment also includes Gulf States, which owns a 10-mile interstate pipeline that extends from Harrison County, Texas to Caddo Parish, Louisiana.
- *NGL Services.* The Partnership owns a 30% membership interest in Lone Star, an entity owning a diverse set of midstream energy assets including NGL pipelines, storage, fractionation and processing facilities located in Texas, New Mexico, Mississippi and Louisiana.
- *Contract Services.* The Partnership owns and operates a fleet of compressors used to provide turn-key natural gas compression services for customer specific systems. The Partnership also owns and operates a fleet of equipment used to provide treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling, dehydration and BTU management.
- *Natural Resources.* The Partnership is involved in the management of coal and natural resources properties and the related collection of royalties. The Partnership also earns revenues from other land management activities, such as selling standing timber, leasing coal-related infrastructure facilities, and collecting oil and gas royalties. This segment also included the Partnership’s 50% interest in Coal Handling, which owns and operates end-user coal handling facilities. The Partnership purchased the remaining 50% interest in these companies effective December 31, 2014.
- *Corporate.* The Corporate segment comprises the Partnership’s corporate assets.

The Partnership accounts for intersegment revenues as if the revenues were to third parties, exclusive of certain cost of capital charges.

Management evaluates the performance of each segment and makes capital allocation decisions through the separate consideration of segment margin and operation and maintenance expenses. Segment margin, for the Gathering and Processing and the Natural Gas Transportation segments is defined as total revenues, including service fees, less cost of sales. In the Contract Services segment, segment margin is defined as revenues less direct costs. The Natural Resources segment margin is generally equal to total revenues
as there is typically minimal cost of sales associated with the management and leasing of properties.

Management believes segment margin is an important measure because it directly relates to volume, commodity price changes, and revenue generating horsepower. Operation and maintenance expenses are a separate measure used by management to evaluate performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of operation and maintenance expenses. These expenses fluctuate depending on the activities performed during a specific period. The Partnership does not deduct operation and maintenance expenses from total revenues in calculating segment margin because management separately evaluates commodity volume and price changes in segment margin. The Partnership does not record segment margin for its investments in unconsolidated affiliates (HPC, MEP, Lone Star, Ranch JV, Aqua - PVR, Mi Vida JV and Sweeny JV) because it records its ownership percentages of their net income as income from unconsolidated affiliates in accordance with the equity method of accounting.

Results for each period, together with amounts related to each segment are shown below:

	Years Ended December 31,		
	2014	2013	2012
External Revenue			
Gathering and Processing	$ 4,570	$ 2,287	$ 1,797
Natural Gas Transportation	—	1	1
NGL Services	—	—	—
Contract Services	307	215	183
Natural Resources	58	—	—
Corporate	16	18	19
Eliminations	—	—	—
Total	$ 4,951	$ 2,521	$ 2,000
Intersegment Revenue			
Gathering and Processing	$ —	$ —	$ —
Natural Gas Transportation	—	—	—
NGL Services	—	—	—
Contract Services	14	15	21
Natural Resources	—	—	—
Corporate	—	—	—
Eliminations	(14)	(15)	(21)
Total	$ —	$ —	$ —
Cost of Sales			
Gathering and Processing	$ 3,381	$ 1,767	$ 1,373
Natural Gas Transportation	—	—	(1)
NGL Services	—	—	—
Contract Services	67	26	15
Natural Resources	—	—	—
Corporate	4	—	—
Eliminations	—	—	—
Total	$ 3,452	$ 1,793	$ 1,387
Segment Margin			
Gathering and Processing	$ 1,189	$ 520	$ 423
Natural Gas Transportation	—	1	2
NGL Services	—	—	—
Contract Services	254	204	189
Natural Resources	58	—	—
Corporate	12	18	20
Eliminations	(14)	(15)	(21)
Total	$ 1,499	$ 728	$ 613

	Years Ended December 31,		
	2014	2013	2012
Operation and Maintenance			
Gathering and Processing	$ 360	$ 237	$ 183
Natural Gas Transportation	—	—	—
NGL Services	—	—	—
Contract Services	86	72	66
Natural Resources	12	—	—
Corporate	3	1	—
Eliminations	(13)	(14)	(21)
Total	$ 448	$ 296	$ 228
Depreciation, Depletion and Amortization			
Gathering and Processing	$ 385	$ 186	$ 159
Natural Gas Transportation	—	—	—
NGL Services	—	—	—
Contract Services	134	98	86
Natural Resources	14	—	—
Corporate	8	3	7
Eliminations	—	—	—
Total	$ 541	$ 287	$ 252
Income from Unconsolidated Affiliates			
Gathering and Processing	$ 5	$ 1	$ (10)
Natural Gas Transportation	72	70	71
NGL Services	116	64	44
Contract Services	—	—	—
Natural Resources	2	—	—
Corporate	—	—	—
Eliminations	—	—	—
Total	$ 195	$ 135	$ 105
Expenditures for Long-Lived Assets			
Gathering and Processing	$ 700	$ 721	$ 395
Natural Gas Transportation	—	—	—
NGL Services	—	—	—
Contract Services	371	311	164
Natural Resources	—	—	—
Corporate	17	2	1
Eliminations	—	—	—
Total	$ 1,088	$ 1,034	$ 560

	December 31,		
	2014	2013	2012
Assets			
Gathering and Processing	$ 12,069	$ 4,748	$ 4,210
Natural Gas Transportation	1,119	991	1,232
NGL Services	1,162	1,070	948
Contract Services	2,035	1,897	1,672
Natural Resources	529	—	—
Corporate	189	76	61
Eliminations	—	—	—
Total	$ 17,103	$ 8,782	$ 8,123
Investments in Unconsolidated Affiliates			
Gathering and Processing	$ 139	$ 36	$ 35
Natural Gas Transportation	1,117	991	1,231
NGL Services	1,162	1,070	948
Contract Services	—	—	—
Natural Resources	—	—	—
Corporate	—	—	—
Eliminations	—	—	—
Total	$ 2,418	$ 2,097	$ 2,214
Goodwill			
Gathering and Processing (1)	$ 732	$ 651	$ 651
Natural Gas Transportation	—	—	—
NGL Services	—	—	—
Contract Services	476	477	477
Natural Resources	15	—	—
Corporate	—	—	—
Eliminations	—	—	—
Total	$ 1,223	$ 1,128	$ 1,128

(1) In 2014, the Partnership recorded a $370 million impairment charge at the Permian reporting unit within this segment.

The table below provides a reconciliation of total segment margin to (loss) income before income taxes:

	Years Ended December 31,		
	2014	2013	2012
Total segment margin	$ 1,499	$ 728	$ 613
Operation and maintenance	(448)	(296)	(228)
General and administrative	(158)	(88)	(100)
Gain (loss) on assets sales, net	1	(2)	(3)
Depreciation, depletion and amortization	(541)	(287)	(252)
Goodwill impairment	(370)	—	—
Income from unconsolidated affiliates	195	135	105
Interest expense, net	(304)	(164)	(122)
Loss on debt refinancing, net	(25)	(7)	(8)
Other income and deductions, net	12	7	29 *
(Loss) income before income taxes	$ (139)	$ 26	$ 34

* Other income and deductions, net for the year ended December 31, 2012, included a one-time producer payment of $16 million related to an assignment of certain contracts.

17. EQUITY-BASED COMPENSATION

In December 2011, the Partnership's unitholders approved the Regency Energy Partners LP 2011 Long-Term Incentive Plan (the "2011 Incentive Plan"), which provides for awards of options to purchase the Partnership's common units; awards of the Partnership's restricted units, phantom units and common units; awards of distribution equivalent rights; awards of common unit appreciation rights; and other unit-based awards to employees, directors and consultants of the Partnership and its affiliates and subsidiaries. The 2011 Incentive Plan will be administered by the Compensation Committee of the board of directors, which may, in its sole discretion, delegate its powers and duties under the 2011 Incentive Plan to the Chief Executive Officer. Up to 3,000,000 of the Partnership's common units may be granted as awards under the 2011 Incentive Plan, with such amount subject to adjustment as provided for under the terms of the 2011 Incentive Plan.

The 2011 Incentive Plan may be amended or terminated at any time by the board of directors or the Compensation Committee without the consent of any participant or unitholder, including an amendment to increase the number of common units available for awards under the plan; however, any material amendment, such as a change in the types of awards available under the plan, would require the approval of the unitholders of the Partnership. The Compensation Committee is also authorized to make adjustments in the terms and conditions of, and the criteria included in awards under the 2011 Incentive Plan in specified circumstances. The 2011 Incentive Plan is effective until December 19, 2021 or, if earlier, the time at which all available units under the 2011 Incentive Plan have been issued to participants or the time of termination of the plan by the board of directors.

Unit-based compensation expense of $10 million, $7 million, and $5 million is recorded in general and administrative expense in the statement of operations for the years ended December 31, 2014, 2013 and 2012, respectively.

Common Unit Options. The fair value of each option award is estimated on the date of grant using the Black-Scholes Option Pricing Model. Upon the exercise of the common unit options, the Partnership intends to settle these obligations with new issues of common units on a net basis. The common unit options activity for the year ended December 31, 2014 is as follows:

Common Unit Options	Units	Weighted Average Exercise Price
Outstanding at the beginning of period	142,550	$ 22.04
Exercised	(34,900)	20.03
Outstanding at end of period	107,650	22.68
Exercisable at the end of the period	107,650	

The common unit options have an intrinsic value of less than $1 million related to non-vested units with a weighted average contractual term of 1.5 years. Intrinsic value is the closing market price of a common unit less the option strike price, multiplied by the number of unit options outstanding as of the end of the period presented. Unit options with an exercise price greater than the end of period closing market price are excluded.

Phantom Units. During 2014, the Partnership awarded 1,450,230 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that vest 60% after the third year of continued employment and 40% after the fifth year of continued employment. Distributions on the phantom units will be paid concurrent with the Partnership’s distribution for common units.

During 2013, the Partnership awarded 62,360 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that generally vest 60% after the third year of continued employment and 40% after the fifth year of continued employment. Distributions on the phantom units will be paid concurrent with the Partnership’s distribution for common units.

In December 2012, the Partnership awarded 495,375 phantom units to senior management and certain key employees. These awards are service condition (time-based) grants that vest 60% after the third year of continued employment and 40% after the fifth year of continued employment. Also during 2012, 8,250 phantom units were awarded to senior management and key employees as service condition (time-based) grants that generally vest ratably over a 5 year period. Distributions on the phantom units will be paid concurrent with the Partnership’s distribution for common units.

The following table presents phantom unit activity for the year ended December 31, 2014:

Phantom Units	**Units**	**Weighted Average Grant Date Fair Value**
Outstanding at the beginning of the period	982,242	$ 23.16
Service condition grants	1,450,230	25.24
Vested service condition	(183,380)	25.25
Forfeited service condition	(81,373)	24.83
Total outstanding at end of period	2,167,719	24.31

During the years ended December 31, 2014, 2013 and 2012, the weighted average grant date fair value per phantom unit granted was $25.24, $25.44, and $21.39, respectively. The total fair value of awards vested was $5 million, $6 million, and $5 million for the years ended December 31, 2014, 2013 and 2012, respectively, based on the market price of Regency common units as of the vesting date.

The Partnership expects to recognize $42 million of unit-based compensation expense related to non-vested phantom units over a period of 3.9 years.

Cash Restricted Units. The Partnership began granting cash restricted units in 2014. These awards are service condition (time-based) grants of notional units that vest 100% after the third year of continued employment. A cash restricted unit entitles the award recipient to receive cash equal to the market price of one Regency common unit as of the vesting date.

The following table presents cash restricted unit activity for the year ended December 31, 2014:

Cash Restricted Units	**Units**
Outstanding at the beginning of the period	—
Service condition grants	400,928
Vested service condition	(500)
Forfeited service condition	(21,100)
Total outstanding at end of period	379,328

Based on the trading price of Regency common units at December 31, 2014, the Partnership expects to recognize $7 million of unit-based compensation expense related to non-vested cash restricted units over a period of 2.5 years.

18. CONSOLIDATING GUARANTOR FINANCIAL INFORMATION

ELG, Aqua - PVR, and ORS do not fully and unconditionally guarantee, on a joint and several basis, the Senior Notes issued and outstanding as of December 31, 2014, by the Partnership and Finance Corp. Included in the Parent financial statements are the Partnership's intercompany investments in all consolidated subsidiaries and the Partnership's investments in unconsolidated affiliates. ELG, Aqua - PVR, and ORS are included in the non-guarantor subsidiaries.

The consolidating financial information for the Parent, Guarantor Subsidiaries, and Non Guarantor Subsidiaries are as follows:

	December 31, 2014				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
ASSETS					
Cash	$ —	$ —	$ 32	$ (8)	$ 24
All other current assets	—	667	13	(1)	679
Property, plant, and equipment, net	—	8,948	353	(84)	9,217
Investments in subsidiaries	19,829	—	—	(19,829)	—
Investments in unconsolidated affiliates	—	2,252	—	166	2,418
All other assets	—	4,765	—	—	4,765
TOTAL ASSETS	$ 19,829	$ 16,632	$ 398	$ (19,756)	$ 17,103
LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST					
All other current liabilities	—	723	34	(1)	756
Long-term liabilities	5,185	1,575	6	(4)	6,762
Noncontrolling interest	—	—	—	120	120
Total partners' capital and noncontrolling interest	14,644	14,334	358	(19,871)	9,465
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$ 19,829	$ 16,632	$ 398	$ (19,756)	$ 17,103

	December 31, 2013				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
ASSETS					
Cash	$ —	$ —	$ 19	$ —	$ 19
All other current assets	—	366	15	—	381
Property, plant, and equipment, net	—	4,244	174	—	4,418
Investments in subsidiaries	10,446	—	—	(10,446)	—
Investments in unconsolidated affiliates	—	1,995	—	102	2,097
All other assets	—	1,867	—	—	1,867
TOTAL ASSETS	$ 10,446	$ 8,472	$ 208	$ (10,344)	$ 8,782
LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST					
All other current liabilities	—	466	9	—	475
Long-term liabilities	2,832	559	—	—	3,391
Noncontrolling interest	—	—	—	102	102
Total partners' capital and noncontrolling interest	7,614	7,447	199	(10,446)	4,814
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$ 10,446	$ 8,472	$ 208	$ (10,344)	$ 8,782

	For the year ended December 31, 2014				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$ —	$ 4,888	$ 66	$ (3)	$ 4,951
Operating costs, expenses, and other	—	4,942	35	(9)	4,968
Operating (loss) income	—	(54)	31	6	(17)
Income from unconsolidated affiliates	—	195	—	—	195
Interest expense, net	(290)	(14)	—	—	(304)
Loss on debt refinancing, net	(24)	(1)	—	—	(25)
Equity in consolidated subsidiaries	166	—	—	(166)	—
Other income and deductions, net	3	9	—	—	12
(Loss) income before income taxes	(145)	135	31	(160)	(139)
Income tax expense (benefit)	4	(2)	1	—	3
Net (loss) income	(149)	137	30	(160)	(142)
Net income attributable to noncontrolling interest	—	—	—	(15)	(15)
Net (loss) income attributable to Regency Energy Partners LP	$ (149)	$ 137	$ 30	$ (175)	$ (157)
Total other comprehensive income	$ —	$ —	$ —	$ —	$ —
Comprehensive (loss) income	(149)	137	30	(160)	(142)
Comprehensive income attributable to noncontrolling interest	—	—	—	15	15
Comprehensive (loss) income attributable to Regency Energy Partners LP	$ (149)	$ 137	$ 30	$ (175)	$ (157)

	For the year ended December 31, 2013				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$ —	$ 2,489	$ 32	$ —	$ 2,521
Operating costs, expenses, and other	3	2,448	15	—	2,466
Operating (loss) income	(3)	41	17	—	55
Income from unconsolidated affiliates	—	135	—	—	135
Interest expense, net	(148)	(16)	—	—	(164)
Loss on debt refinancing, net	(7)	—	—	—	(7)
Equity in consolidated subsidiaries	172	—	—	(172)	—
Other income and deductions, net	7	—	—	—	7
Income before income taxes	21	160	17	(172)	26
Income tax expense (benefit)	1	(2)	—	—	(1)
Net income	20	162	17	(172)	27
Net income attributable to noncontrolling interest	—	(8)	—	—	(8)
Net income attributable to Regency Energy Partners LP	$ 20	$ 154	$ 17	$ (172)	$ 19
Total other comprehensive income	$ —	$ —	$ —	$ —	$ —
Comprehensive income	20	162	17	(172)	27
Comprehensive income attributable to noncontrolling interest	—	8	—	—	8
Comprehensive income attributable to Regency Energy Partners LP	$ 20	$ 154	$ 17	$ (172)	$ 19

	For the year ended December 31, 2012				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Revenues	$ —	$ 1,985	$ 15	$ —	$ 2,000
Operating costs, expenses, and other	10	1,951	9	—	1,970
Operating (loss) income	(10)	34	6	—	30
Income from unconsolidated affiliates	—	105	—	—	105
Interest expense, net	(104)	(18)	—	—	(122)
Gain (loss) on debt refinancing, net	(8)	—	—	—	(8)
Equity in consolidated subsidiaries	141	—	—	(141)	—
Other income and deductions, net	14	15	—	—	29
Income before income taxes	33	136	6	(141)	34
Income tax expense (benefit)	1	(1)	—	—	—
Net income	32	137	6	(141)	34
Net income attributable to noncontrolling interest	—	(2)	—	—	(2)
Net income attributable to Regency Energy Partners LP	$ 32	$ 135	$ 6	$ (141)	$ 32
Total other comprehensive income (loss)	$ —	$ 2	$ —	$ —	$ 2
Comprehensive income	32	139	6	(141)	36
Comprehensive income attributable to noncontrolling interest	—	2	—	—	2
Comprehensive income attributable to Regency Energy Partners LP	$ 32	$ 137	$ 6	$ (141)	$ 34

	For the year ended December 31, 2014				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows from operating activities	$ —	$ 664	$ 56	$ (1)	$ 719
Cash flows from investing activities	—	(2,130)	(30)	(9)	(2,169)
Cash flows from financing activities	—	1,466	(13)	2	1,455
Change in cash	—	—	13	(8)	5
Cash at beginning of period	—	—	19	—	19
Cash at end of period	$ —	$ —	$ 32	$ (8)	$ 24

	For the year ended December 31, 2013				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows from operating activities	$ —	$ 424	$ 12	$ —	$ 436
Cash flows from investing activities	—	(1,303)	(90)	—	(1,393)
Cash flows from financing activities	—	879	44	—	923
Change in cash	—	—	(34)	—	(34)
Cash at beginning of period	—	—	53	—	53
Cash at end of period	$ —	$ —	$ 19	$ —	$ 19

	For the year ended December 31, 2012				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated Partnership
Cash flows from operating activities	$ —	$ 316	$ 8	$ —	$ 324
Cash flows from investing activities	—	(746)	(61)	—	(807)
Cash flows from financing activities	—	430	105	—	535
Change in cash	—	—	52	—	52
Cash at beginning of period	—	—	1	—	1
Cash at end of period	$ —	$ —	$ 53	$ —	$ 53

19. QUARTERLY FINANCIAL DATA (UNAUDITED)

	Quarter Ended			
2014	December 31	September 30	June 30	March 31
Operating revenues	$ 1,427	$ 1,483	$ 1,178	$ 863
Operating (loss) income	(218)	144	35	22
Net (loss) income attributable to Regency Energy Partners LP	(261)	103	(8)	9
Earnings per common units:				
Basic net (loss) income per common unit	(0.67)	0.23	(0.05)	0.00
Diluted net (loss) income per common unit	(0.67)	0.23	(0.05)	0.00

	Quarter Ended			
2013	December 31	September 30	June 30	March 31
Operating revenues	$ 677	$ 665	$ 639	$ 540
Operating income (loss)	12	24	34	(15)
Net (loss) income attributable to Regency Energy Partners LP	(1)	39	10	(29)
Earnings per common units:				
Basic net (loss) income per common unit	(0.03)	0.16	0.07	(0.06)
Diluted net (loss) income per common unit	(0.03)	0.05	0.07	(0.06)

The three months ended December 31, 2014 includes a $370 million goodwill impairment charge recorded related to the Permian reporting unit within the Gathering and Processing segment.