Tallgrass Energy Partners, LP
Form 10-Q
October 30, 2014

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

FORM 10-Q

(Mark One)

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

For the Quarterly Period Ended September 30, 2014

or

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

Commission file number 001-35917

Tallgrass Energy Partners, LP
(Exact name of registrant as specified in its charter)

Delaware	4,922	46-1972941
(State or other Jurisdiction of Incorporation or Organization)	(Primary Standard Industrial Classification Code Number)	(IRS Employer Identification Number)

4200 W. 115th Street, Suite 350
Leawood, Kansas 66211
(913) 928-6060
(Address, including zip code, and telephone number, including area code, of Registrant's principal executive offices)

George E. Rider
4200 W. 115th Street, Suite 350
Leawood, Kansas 66211
(913) 928-6060
(Address, including zip code, and telephone number, including area code, of Agent for service)

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 ý 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 ý No ¨

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. (Check one):

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

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

On October 28, 2014, the Registrant had 32,805,480 Common Units, 16,200,000 Subordinated Units, and 834,391 General Partner Units outstanding.

TALLGRASS ENERGY PARTNERS, LP
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Glossary of Common Industry and Measurement Terms

Bakken oil production area: Montana and North Dakota in the United States and Saskatchewan and Manitoba in Canada.

Barrel (or bbl): Forty two U.S. gallons.

Bbl/d: Barrels per day.

Base Gas (or Cushion Gas): The volume of gas that is intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates.

BBtu: One billion British Thermal Units.

Bcf: One billion cubic feet.

British Thermal Units or Btus: the amount of heat energy needed to raise the temperature of one pound of water by one degree Fahrenheit.

Condensate: A NGL with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.

Contract barrel: Customers that commit to ship a contracted quantity of crude oil in exchange for assurance of capacity and deliverability to delivery points.

Delivery point: the point at which product in a pipeline is delivered to the end user.

Dry gas: A gas primarily composed of methane and ethane where heavy hydrocarbons and water either do not exist or have been removed through processing.

Dth: A dekatherm, which is a unit of energy equal to 10 therms or one million British thermal units.

End-user markets: The ultimate users and consumers of transported energy products.

FERC: Federal Energy Regulatory Commission.

Firm transportation and storage services: Those services pursuant to which customers receive firm assurances regarding the availability of capacity and deliverability of natural gas on our assets up to a contracted amount at specified receipt and delivery points.

GAAP: Generally accepted accounting principles in the United States of America.

GHGs: Greenhouse gases.

Header system: Networks of medium-to-large-diameter high pressure pipelines that connect local gathering systems to large diameter high pressure long-haul transportation pipelines.

HP: Horsepower.

Interruptible transportation and storage services: Those services pursuant to which customers receive only limited assurances regarding the availability of capacity and deliverability in transportation or storage facilities, as applicable, and pay fees based on their actual utilization of such assets.

Line fill: The volume of oil, in barrels, in the pipeline from the origin to the destination.

Liquefied natural gas or LNG: Natural gas that has been cooled to minus 161 degrees Celsius for transportation, typically by ship. The cooling process reduces the volume of natural gas by 600 times.

Local distribution company or LDC: LDCs are involved in the delivery of natural gas to consumers within a specific geographic area.

MMBtu: One million British Thermal Units.

Mcf: One thousand cubic feet.

MMcf: One million cubic feet.

Natural gas liquids or NGLs: Those hydrocarbons in natural gas that are separated from the natural gas as liquids through the process of absorption, condensation, adsorption or other methods in natural gas processing or cycling plants. Generally such liquids consist of propane and heavier hydrocarbons and are commonly referred to as lease condensate, natural gasoline and liquefied petroleum gases. Natural gas liquids include natural gas plant liquids (primarily ethane, propane, butane and isobutane) and lease condensate (primarily pentanes produced from natural gas at lease separators and field facilities).
Non-contract barrel: Customers subject to the transportation of crude oil based on availability of capacity and deliverability with no assurance of future capacity.
No-notice service: Those services pursuant to which customers receive the right to transport or store natural gas on assets outside of the daily nomination cycle without incurring penalties.
NYMEX: New York Mercantile Exchange.
Park and loan services: Those services pursuant to which customers receive the right to store natural gas in (park), or borrow gas from (loan), our facilities on a seasonal basis.
PHMSA: The United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration.
Play: A proven geological formation that contains commercial amounts of hydrocarbons.
Receipt point: The point where production is received by or into a gathering system or transportation pipeline.
Reservoir: A porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (crude oil and/or natural gas) which is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.
Residue gas: The natural gas remaining after being processed or treated.
Shale gas: Natural gas produced from organic (black) shale formations.
Tailgate: The point at which processed natural gas and NGLs leave a processing facility for end-user markets.
TBtu: One trillion British Thermal Units.
Tcf: One trillion cubic feet.
Throughput: The volume of natural gas transported or passing through a pipeline, plant, terminal or other facility during a particular period.
Wellhead: The equipment at the surface of a well that is used to control the well's pressure; also, the point at which the hydrocarbons and water exit the ground.
Working gas: The volume of gas in the storage reservoir that is in addition to the cushion or base gas. It may or may not be completely withdrawn during any particular withdrawal season. Conditions permitting, the total working capacity could be used more than once during any season.
Working gas storage capacity: The maximum volume of natural gas that can be cost-effectively injected into a storage facility and extracted during the normal operation of the storage facility. Effective working gas storage capacity excludes cushion gas and non-cycling working gas.
X/d: The applicable measurement metric per day. For example, MMcf/d means one million cubic feet per day.

PART 1—FINANCIAL INFORMATION
Item 1. Financial Statements
TALLGRASS ENERGY PARTNERS, LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

	September 30, 2014	December 31, 2013
	(in thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$885	$—
Accounts receivable, net	29,194	30,033
Receivable from related parties	237,537	—
Gas imbalances	1,778	3,128
Inventories	91,793	5,549
Prepayments and other current assets	23,120	16,986
Total Current Assets	384,307	55,696
Property, plant and equipment, net	1,779,749	1,116,806
Goodwill	343,288	334,715
Intangible asset, net	106,556	102,567
Unconsolidated investment	—	1,255
Deferred financing costs	5,914	4,512
Deferred charges and other assets	15,721	15,862
Total Assets	$2,635,535	$1,631,413
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities:		
Accounts payable, including $96,831 and $89,212 related to variable interest entities	$122,616	$149,452
Accounts payable to related parties, including $20,519 and $0 related to variable interest entities	23,596	7,137
Gas imbalances	2,785	3,664
Derivative liabilities at fair value	44	184
Accrued taxes	4,156	5,520
Accrued other current liabilities, including $92,922 and $0 related to variable interest entities	105,619	16,783
Total Current Liabilities	258,816	182,740
Long-term debt	568,000	135,000
Other long-term liabilities and deferred credits	6,776	4,572
Total Long-term Liabilities	574,776	139,572
Commitments and Contingencies		
Equity:		
Predecessor Equity	—	247,221
Common unitholders 32,805,480 and 24,300,000 units issued and outstanding at September 30, 2014 and December 31, 2013	795,315	455,197
Subordinated unitholder 16,200,000 units issued and outstanding at September 30, 2014 and December 31, 2013	273,394	274,666
General partner 834,391 and 826,531 units issued and outstanding at September 30, 2014 and December 31, 2013	(38,659)	14,078
Total Partners' Equity	1,030,050	991,162

Noncontrolling interests	$771,893	$317,939
Total Equity	$1,801,943	$1,309,101
Total Liabilities and Equity	$2,635,535	$1,631,413

The accompanying notes are an integral part of these condensed consolidated financial statements.
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TALLGRASS ENERGY PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands, except per unit amounts)			
Revenues:				
Natural gas liquids sales	$47,321	$32,216	$132,557	$97,307
Natural gas sales	1,809	3,381	9,330	8,079
Transportation services	30,745	28,916	95,418	89,443
Processing and other revenues	10,078	4,205	24,747	8,924
Total Revenues	89,953	68,718	262,052	203,753
Operating Costs and Expenses:				
Cost of sales and transportation services	49,096	35,004	144,921	101,447
Operations and maintenance	9,961	9,277	28,029	25,869
Depreciation and amortization	10,071	9,870	27,905	30,106
General and administrative	7,448	7,321	21,221	19,867
Taxes, other than income taxes	1,797	1,845	5,392	5,554
Total Operating Costs and Expenses	78,373	63,317	227,468	182,843
Operating Income	11,580	5,401	34,584	20,910
Other (Expense) Income:				
Interest expense, net	(1,058)	(1,376)	(4,492)	(10,435)
Gain on remeasurement of unconsolidated investment	—	—	9,388	—
Loss on extinguishment of debt	—	—	—	(17,526)
Equity in earnings of unconsolidated investment	—	—	717	—
Other income, net	731	1,070	2,400	1,871
Total Other (Expense) Income	(327)	(306)	8,013	(26,090)
Net Income (Loss)	11,253	5,095	42,597	(5,180)
Net loss attributable to noncontrolling interests	191	505	1,256	1,516
Net Income (Loss) attributable to partners	$11,444	$5,600	$43,853	$(3,664)
Allocation of income (loss) to the limited partners:				
Net income (loss) attributable to partners	$11,444	$5,600	$43,853	$(3,664)
Predecessor operations interest in net loss (income)	1,134	1,406	(1,508)	4,014
Net income attributable to partners	12,578	7,006	42,345	350
Net income attributable to partners prior to May 17, 2013	—	—	—	(6,982)
Net income (loss) attributable to partners subsequent to May 17, 2013	12,578	7,006	42,345	(6,632)
General partner interest in net (income) loss subsequent to May 17, 2013	(1,435)	(140)	(2,912)	133
Common and subordinated unitholders' interest in net income (loss) subsequent to May 17, 2013	$11,143	$6,866	$39,433	$(6,499)
Basic net income (loss) per common and subordinated unit	$0.24	$0.17	$0.92	$(0.16)
Diluted net income (loss) per common and subordinated unit	$0.23	$0.17	$0.90	$(0.16)
Basic average number of common and subordinated units outstanding	46,855	40,500	42,770	40,417
Diluted average number of common and subordinated units outstanding	47,948	40,863	43,771	40,417

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

TALLGRASS ENERGY PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Nine Months Ended September 30,	
	2014	2013
	(in thousands)	
Cash Flows from Operating Activities:		
Net income (loss)	$42,597	$(5,180)
Adjustments to reconcile net income (loss) to net cash flows from operating activities:		
Depreciation and amortization	28,946	31,584
Gain on remeasurement of unconsolidated investment	(9,388)	—
Loss on extinguishment of debt	—	17,526
Noncash compensation expense	3,724	948
Changes in components of working capital:		
Accounts receivable and other	2,592	11,688
Gas imbalances	1,392	2,208
Prepayments	(2,566)	(193)
Inventories	(4,661)	(166)
Accounts payable and accrued liabilities	(14,990)	(3,035)
Other operating, net	(402)	(5,038)
Net Cash (Used In) Provided by Operating Activities	47,244	50,342
Cash Flows from Investing Activities:		
Acquisition of Trailblazer	(150,000)	—
Capital expenditures	(642,216)	(237,059)
Acquisition of additional equity interests in Water Solutions	(7,600)	—
Acquisition of Pony Express membership interest	(27,000)	—
Issuance of related party loan	(270,000)	—
Other investing, net	(2,268)	(301)
Net Cash Used in Investing Activities	(1,099,084)	(237,360)
Cash Flows from Financing Activities:		
Proceeds from public offering, net of offering costs	319,588	290,498
Borrowings under revolving credit facility	433,000	226,000
Distributions to unitholders	(46,454)	(5,877)
Contribution from TD	27,488	—
Contributions from Predecessor Member, net	312,125	200,262
Contributions from noncontrolling interest	5,429	—
Payments for deferred financing costs	(2,373)	(5,157)
Repayment of debt assumed from TD	—	(400,000)
Distributions to Member, net	—	(118,538)
Other financing, net	3,922	450
Net Cash Provided by (Used in) Financing Activities	1,052,725	187,638
Net Change in Cash and Cash Equivalents	885	620
Cash and Cash Equivalents, beginning of period	—	—
Cash and Cash Equivalents, end of period	$885	$620
Supplemental Disclosures:		
Cash payments for interest	$4,414	$2,155

Schedule of Noncash Investing and Financing Activities:		
Property, plant and equipment acquired via the cash management agreement with TD	$32,479	$—
Increase in accrual for payment of property, plant and equipment	$2,903	$39,866
Receivable for unreimbursed stock compensation from TD	$426	$373
Increase in accrual for reimbursable construction in progress projects	$—	$3,516
Fair value of TIGT and TMID assets contributed by TD	$—	$1,027,127
Fair value of TIGT and TMID liabilities contributed by TD	$—	$(566,849)

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

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TALLGRASS ENERGY PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(UNAUDITED)

	Predecessor Equity	Limited Partners Common	Subordinated	General Partner	Total Partners' Equity	Noncontrolling Interests	Total Equity
Balance at January 1, 2014	$ 247,221	$ 455,197	$ 274,666	$ 14,078	$ 991,162	$ 317,939	$ 1,309,101
Net Income	1,508	24,181	15,252	2,912	43,853	(1,256)	42,597
Equity issuance, net of offering costs	—	319,588	—	—	319,588	—	319,588
Noncash compensation expense	—	7,443	—	—	7,443	—	7,443
Distributions to unitholders	—	(28,117)	(16,524)	(1,813)	(46,454)	—	(46,454)
Contribution from TD	—	—	—	27,488	27,488	—	27,488
(Distributions to) Contributions from Predecessor Member, net	(97,887)	—	—	—	(97,887)	410,012	312,125
Distributions to Noncontrolling Interests	—	—	—	—	—	(37)	(37)
Issuance of general partner units	—	—	—	263	263	—	263
Acquisition of Trailblazer	(91,090)	14,023	—	(72,933)	(150,000)	—	(150,000)
Acquisition of Water Solutions	—	—	—	—	—	1,400	1,400
Acquisition of Pony Express membership interest	(59,752)	3,000	—	(8,654)	(65,406)	38,406	(27,000)
Contributions from noncontrolling interest	—	—	—	—	—	5,429	5,429
Balance at September 30, 2014	$ —	$ 795,315	$ 273,394	$ (38,659)	$ 1,030,050	$ 771,893	$ 1,801,943

	TEP Predecessor Member's Capital	Predecessor Equity	Limited Partners Common	Subordinated	General Partner	Total Partners' Equity	Noncontrolling Interests	Total Equity
Balance at January 1, 2013	$ 571,834	$ 121,446	$ —	$ —	$ —	$ 693,280	$ 70,397	$ 763,677
Net income (loss) attributable to to the period from January 1, 2013 to May 16, 2013	6,982	(1,172)	—	—	—	5,810	(761)	5,049
Distributions to Member, net	(118,538)	—	—	—	—	(118,538)	—	(118,538)
Contribution of net assets of TIGT and TMID	(460,278)	—	167,051	278,992	14,235	—	—	—

Issuance of units to public (including underwriter over-allotment), net of offering and other costs	—	—	290,498	—	—	290,498	—	290,498
Net loss attributable to the period from May 17, 2013 to September 30, 2013	—	(2,842)	(3,899)	(2,600)	(133)	(9,474)	(755)	(10,229)
Distributions to unitholders	—	—	(3,455)	(2,304)	(118)	(5,877)	—	(5,877)
Noncash compensation expense	—	—	2,078	—	—	2,078	—	2,078
Contributions from Predecessor Member, net	—	68,574	—	—	—	68,574	131,688	200,262
Balance at September 30, 2013	$ —	$ 186,006	$ 452,273	$ 274,088	$ 13,984	$ 926,351	$ 200,569	$ 1,126,920

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

TALLGRASS ENERGY PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. Description of Business

Tallgrass Energy Partners, LP ("TEP" or the "Partnership") is a Delaware limited partnership formed in February 2013. TEP closed its initial public offering ("IPO") on May 17, 2013 and on July 25, 2014 closed a public offering of an additional 8,050,000 common units. The 22,650,000 common units held by the public constitute approximately 46.2% of TEP's aggregate outstanding common and subordinated units and approximately 45.4% of TEP's aggregate outstanding common, subordinated and general partner units at September 30, 2014. Tallgrass Development, LP ("TD") held 10,155,480 common units and 16,200,000 subordinated units at September 30, 2014, which comprised approximately 53.8% of TEP's aggregate outstanding common and subordinated units and approximately 52.9% of TEP's aggregate outstanding common, subordinated and general partner units. In addition, 834,391 general partner units, representing a 1.7% general partner interest in TEP at September 30, 2014, and all of the incentive distribution rights ("IDRs") are held by Tallgrass MLP GP, LLC (the "general partner"). In connection with the IPO, TEP entered into a revised partnership agreement on May 17, 2013. The amended and restated partnership agreement requires TEP to distribute its available cash on a quarterly basis, subject to certain terms and conditions, beginning with the quarter ending June 30, 2013. For additional information, see Note 11 - Partnership Equity and Distributions.

The term "TEP Predecessor" refers to Tallgrass Energy Partners Predecessor, which is comprised of the businesses described below that were owned by TD, from November 13, 2012 through the completion of the IPO on May 17, 2013.

The businesses included in the TEP Predecessor consist of:

- Tallgrass Interstate Gas Transmission, LLC ("TIGT"), which owns an interstate gas pipeline and storage system (the "TIGT System") that is regulated by the FERC. TIGT currently has approximately 4,645 miles of varying diameter natural gas transmission lines in Colorado, Kansas, Missouri, Nebraska and Wyoming.
- Tallgrass Midstream, LLC ("TMID"), which owns and operates one treating and two processing plants in Wyoming.

The term "Trailblazer Predecessor" refers to Trailblazer Pipeline Company LLC ("Trailblazer"), which TEP acquired on April 1, 2014, and the term "Pony Express Predecessor" refers to Tallgrass Pony Express Pipeline, LLC ("Pony Express"), of which TEP acquired a 33.3% membership interest effective September 1, 2014 (TEP Predecessor, Trailblazer Predecessor and Pony Express Predecessor are collectively, the "Predecessor Entities"), as further discussed in Note 2 – Summary of Significant Accounting Policies. Financial results for all prior periods have been recast to reflect the operations of the Predecessor Entities. Predecessor Equity as presented in the condensed consolidated financial statements represents the capital account activity of Trailblazer Predecessor prior to April 1, 2014 and of Pony Express Predecessor prior to September 1, 2014.

Trailblazer is an approximately 436-mile FERC regulated natural gas pipeline system that begins along the border of Wyoming and Colorado and extends to Beatrice, Nebraska. Pony Express owns and is developing an oil pipeline project, which we collectively refer to as the Pony Express Project. That project consists of two components that include (i) the conversion of an approximately 430-mile natural gas pipeline and the construction of an approximately 260-mile southward pipeline extension that result in an oil pipeline from Guernsey, Wyoming to Cushing, Oklahoma ("the Pony Express Mainline"), and (ii) the construction of an approximately 66-mile lateral in northeast Colorado that will interconnect with the mainline ("the Northeast Colorado Lateral"). The project is being completed in stages, with the Pony Express Mainline placed in service in October 2014, while the Northeast Colorado Lateral is expected to be in service sometime during the first half of 2015.

2. Summary of Significant Accounting Policies

Basis of Presentation

These unaudited condensed consolidated financial statements and related notes for the three and nine months ended September 30, 2014 and 2013 were prepared in accordance with the accounting principles contained in the Financial Accounting Standards Board's Accounting Standards Codification, the single source of generally accepted accounting principles in the United States of America ("GAAP") for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. The year-end balance sheet data was derived from audited financial statements but has not been audited as recast for Trailblazer and Pony Express and does not include disclosures required by GAAP for annual periods. The unaudited condensed consolidated financial statements for the three and nine months ended September 30, 2014 and 2013 include all normal, recurring adjustments and disclosures that we believe are necessary for a fair presentation of the results for the interim periods. In this report, the Financial Accounting Standards Board is referred to as the FASB and the FASB Accounting Standards Codification is referred to as the Codification or ASC. Certain prior period amounts have been reclassified to conform to the current presentation.

TEP’s financial results for the three and nine months ended September 30, 2014 are not necessarily indicative of the results that may be expected for the full year ending December 31, 2014. These unaudited condensed consolidated financial statements should be read in conjunction with TEP’s audited consolidated financial statements and notes thereto included in its Annual Report on Form 10-K for the year ended December 31, 2013 (“2013 Form 10-K”) filed with the United States Securities and Exchange Commission (the “SEC”) on March 11, 2014.

The accompanying consolidated financial statements of TEP include historical cost-basis accounts of the assets of TEP Predecessor, contributed to TEP by TD in connection with the IPO, for the periods prior to May 17, 2013, the closing date of TEP’s IPO, as well as Trailblazer for the periods prior to April 1, 2014, the date TEP acquired Trailblazer from TD, and Pony Express for the periods prior to September 1, 2014, the date TEP acquired a 33.3% membership interest in Pony Express, and include charges from TD for direct costs and allocations of indirect corporate overhead. Management believes that the allocation methods are reasonable, and that the allocations are representative of costs that would have been incurred on a stand-alone basis. Both TEP and TEP Predecessor are considered “entities under common control” as defined under GAAP and, as such, the transfers between the entities of the assets and liabilities have been recorded by TEP at historical cost. TEP, or the Partnership, as used herein refers to the consolidated financial results and operations for TEP Predecessor from its inception through its contribution to TEP and thereafter.

As further discussed in Note 4 – Acquisitions, TEP closed the acquisition of Trailblazer on April 1, 2014 and the acquisition of a 33.3% membership interest in Pony Express effective September 1, 2014. As the acquisitions of Trailblazer and Pony Express are considered transactions between entities under common control, and a change in reporting entity, the financial information presented for prior periods has been recast to include Trailblazer and Pony Express for all periods presented.

The condensed consolidated financial statements include the accounts of TEP and its subsidiaries and controlled affiliates. Significant intra-entity items have been eliminated in the presentation. TEP was determined to be the primary beneficiary of Pony Express and has consolidated Pony Express accordingly. Net equity distributions of the TEP Predecessor and the Predecessor Entities included in the Consolidated Statements of Cash Flows represent transfers of cash as a result of TD’s centralized cash management systems prior to May 17, 2013, and prior to April 1, 2014 for Trailblazer and September 1, 2014 for Pony Express, under which cash balances were swept daily and recorded as loans from the subsidiaries to TD. These loans were then periodically recorded as equity distributions. Pony Express participates in a cash management agreement with TD, which holds a 66.7% common membership interest in Pony Express, under which cash balances are swept daily and recorded as loans from Pony Express to TD.

A variable interest entity ("VIE") is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has a variable interest that could be significant to the VIE and the power to direct the activities that most significantly impact the entity’s economic performance. TEP has presented separately on its condensed consolidated balance sheets, to the extent material, the assets of its consolidated VIE that can only be used to settle specific obligations of the consolidated VIE, and the liabilities of TEP's consolidated VIE for which creditors do not have recourse to TEP's general credit. Pony Express is considered to be a VIE under the applicable authoritative guidance. Based on a qualitative analysis in accordance with the applicable authoritative guidance, TEP has determined that it has the power to direct matters that most significantly impact the activities of Pony Express and has the right to receive benefits of Pony Express that could potentially be significant to Pony Express. TEP has consolidated Pony Express as TEP is the primary beneficiary. For additional information see Note 3 – Variable Interest Entities.

Use of Estimates

Certain amounts included in or affecting these condensed consolidated financial statements and related disclosures must be estimated, requiring management to make certain assumptions with respect to values or conditions which cannot be known with certainty at the time the financial statements are prepared. These estimates and assumptions affect the amounts reported for assets, liabilities, revenues, and expenses during the reporting period, and the disclosure of contingent assets and liabilities at the date of the financial statements. Management evaluates these estimates on an ongoing basis, utilizing historical experience, consultation with experts and other methods it considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from these estimates. Any effects on TEP's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Income Taxes

Prior to September 1, 2014, TEP was comprised solely of limited liability companies that have elected to be treated as partnerships for income tax purposes. As discussed above, effective September 1, 2014 TEP acquired a 33.3% membership interest in Pony Express, which in turn owns 99.8% of Tallgrass Pony Express Pipeline (Colorado), Inc. ("PXP Colorado"), a C corporation. PXP Colorado is currently in the process of constructing the Northeast Colorado Lateral and has not yet commenced operations or generated any income. Accordingly, no provision for federal or state income taxes has been recorded in the financial statements of TEP.

Accounting Pronouncements Issued But Not Yet Effective

ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)"

In May 2014, the Financial Accounting Standards Board ("FASB") issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606). ASU 2014-09 provides a comprehensive and converged set of principles-based revenue recognition guidelines which supersede the existing industry and transaction-specific standards. The core principle of the new guidance is 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. To achieve this core principle, entities must apply a five step process to (1) identify the contract with a customer; (2) identify the performance obligations in the contract; (3) determine the transaction price; (4) allocate the transaction price to the performance obligations in the contract; and (5) recognize revenue when (or as) the entity satisfies a performance obligation. ASU 2014-09 also mandates disclosure of sufficient information to enable users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The disclosure requirements include qualitative and quantitative information about contracts with customers, significant judgments and changes in judgments, and assets recognized from the costs to obtain or fulfill a contract.

The amendments in ASU 2014-09 are effective for public entities for annual reporting periods beginning after December 15, 2016, and for interim periods within that reporting period. Early application is not permitted. TEP is currently evaluating the impact of ASU 2014-09, however it is not expected to have a material impact on TEP's financial position and results of operations.

ASU No. 2014-12, "Compensation - Stock Compensation (Topic 718), Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period"

In June 2014, The FASB issued ASU No. 2014-12, Compensation - Stock Compensation (Topic 718), Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period. ASU 2014-12 provides explicit guidance on accounting for share-based payments requiring a specific performance target to be achieved in order for employees to become eligible to vest in the awards when that performance target may be achieved after the requisite service period for the award. The ASU requires that such performance targets be treated as a performance condition, and should not be reflected in the estimate of the grant-date fair value of the award. Instead, compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved. ASU 2014-12 is effective for annual periods and interim periods within those annual periods beginning after December 15, 2015. Early adoption is permitted. The adoption of ASU 2014-12 is not expected to have a material impact on TEP's financial position and results of operations.

3. Variable Interest Entities

TEP, as the managing member of Pony Express, has voting rights disproportionate to its ownership interest. In addition, TEP does not have the obligation to absorb expected losses as a result of the minimum quarterly preference payments as discussed in Note 4 – Acquisitions. As a result, TEP has determined that Pony Express is a VIE of which TEP is the primary beneficiary and consolidates Pony Express accordingly.

TEP has not provided any additional financial support to Pony Express other than its initial capital contribution of $570 million and has no contractual commitments or obligations to provide additional financial support. In the event that the costs of construction of the Pony Express Mainline and Northeast Colorado Lateral exceed the $270 million retained by Pony Express as discussed in Note 4 – Acquisitions, TD is obligated to fund the remaining costs.

The carrying amounts and classifications of the Pony Express assets and liabilities included in TEP's condensed consolidated balance sheet at September 30, 2014 and December 31, 2013 are as follows:

	September 30, 2014	December 31, 2013
	(in thousands)	
Current assets	$341,417	$—
Noncurrent assets	1,225,638	566,156
Total assets	$1,567,055	$566,156
Current liabilities	$210,944	$89,247
Noncurrent liabilities	—	—
Total liabilities	$210,944	$89,247

4. Acquisitions

On April 1, 2014, TEP closed the acquisition of Trailblazer from a wholly owned subsidiary of TD for total consideration valued at approximately $164 million, consisting of $150 million in cash and the issuance of 385,140 common units (valued at approximately $14 million based on the March 31, 2014 closing price of TEP’s common units). On that same date, the general partner contributed additional capital in the amount of approximately $263,000 in exchange for the issuance of 7,860 general partner units in order to maintain its 2% general partner interest. The acquisition of Trailblazer represents a change in reporting entity and a transaction between entities under common control. The excess purchase price over the net book value of Trailblazer's assets and liabilities was accounted for as a deemed distribution as discussed further in Note 11 – Partnership Equity and Distributions.

Effective September 1, 2014, TEP acquired a 33.3% membership interest in Pony Express for total consideration of approximately $600 million. At closing, Pony Express, TD, and TEP entered into a Second Amended and Restated Limited Liability Company Agreement of Pony Express effective September 1, 2014, which sets forth the relative rights of TD and TEP as the owners of Pony Express. Of the total consideration of $600 million, TEP directly paid TD $30 million, consisting of $27 million in cash and 70,340 TEP common units with an aggregate fair value of approximately $3 million, in exchange for the transfer by TD to TEP of a 1.9585% membership interest in Pony Express (as such percentage is computed before giving effect to the issuance of the new membership interest by Pony Express to TEP). TEP also contributed cash of $570 million to Pony Express in exchange for a newly issued membership interest which, when combined with the membership interest transferred from TD and the parties' entry at closing into the Second Amended and Restated Limited Liability Company Agreement of Pony Express, constitutes TEP's 33.3% membership interest in Pony Express, which represents 100% of the preferred membership units issued by Pony Express. Of the $570 million cash consideration received by Pony Express, $300 million was immediately distributed to TD at closing and $270 million is maintained by Pony Express to fund the estimated remaining costs of construction for the Pony Express Mainline and the Northeast Colorado Lateral. The $270 million cash balance was subsequently swept to TD under a cash management agreement between Pony Express and TD and was recorded as a related party loan which bears interest at TD's incremental borrowing rate.

The terms of the transaction provide TEP a minimum quarterly preference payment of $16.65 million through the quarter ending September 30, 2015 (pro-rated to approximately $5.4 million for the quarter ending September 30, 2014) with distributions thereafter shared in accordance with the terms of the Second Amended and Restated Limited Liability Company Agreement of Pony Express. TEP has determined that Pony Express is a VIE of which TEP is the primary beneficiary, and consolidates Pony Express accordingly. For additional discussion and disclosure, see Note 3 – Variable Interest Entities. The acquisition of Pony Express represents a transaction between entities under common control and a change in reporting entity.

Historical Financial Information

The results of our acquisitions of Trailblazer and Pony Express are included in the consolidated balance sheets as of September 30, 2014 and December 31, 2013. The following table presents the previously reported December 31, 2013 consolidated balance sheet, adjusted for the acquisitions of Trailblazer and Pony Express:

	As of December 31, 2013			
	TEP	Consolidate Trailblazer Pipeline Company LLC	Consolidate Tallgrass Pony Express Pipeline, LLC	TEP (As currently reported)
	(in thousands)			
ASSETS				
Current Assets:				
Accounts receivable, net	$27,615	$2,418	$—	$30,033
Gas imbalances	2,598	530	—	3,128
Inventories	5,148	401	—	5,549
Prepayments and other current assets	16,986	—	—	16,986
Total Current Assets	52,347	3,349	—	55,696
Property, plant and equipment, net	594,911	62,869	459,026	1,116,806
Goodwill	304,474	30,241	—	334,715
Intangible asset, net	—	—	102,567	102,567
Unconsolidated investment	1,255	—	—	1,255
Deferred financing costs	4,512	—	—	4,512
Deferred charges and other assets	10,299	1,000	4,563	15,862
Total Assets	$967,798	$97,459	$566,156	$1,631,413
LIABILITIES AND PARTNERS' EQUITY				
Current Liabilities:				
Accounts payable	$54,621	$5,619	$89,212	$149,452
Accounts payable to related parties	7,134	3	—	7,137
Gas imbalances	3,142	522	—	3,664
Derivative liabilities at fair value	184	—	—	184
Accrued taxes	4,427	1,093	—	5,520
Accrued other current liabilities	14,777	1,971	35	16,783
Total Current Liabilities	84,285	9,208	89,247	182,740
Long-term debt	135,000	—	—	135,000
Other long-term liabilities and deferred credits	4,572	—	—	4,572
Total Long-term Liabilities	139,572	—	—	139,572
Partners' Equity:				
Net Equity	743,941	88,251	476,909	1,309,101
Total Partners' Equity	743,941	88,251	476,909	1,309,101
Total Liabilities and Partners' Equity	$967,798	$97,459	$566,156	$1,631,413

The results of our acquisitions of Trailblazer and Pony Express are included in the condensed consolidated statements of income for the three and nine months ended September 30, 2014 and 2013. The following tables present the previously reported condensed consolidated statements of income for the three and nine months ended September 30, 2013, adjusted for the acquisitions of Trailblazer and Pony Express:

	Three Months Ended September 30, 2013			
	TEP	Consolidate Trailblazer Pipeline Company LLC	Consolidate Tallgrass Pony Express Pipeline, LLC	TEP (As currently reported)
	(in thousands)			
Revenues:				
Natural gas liquids sales	$32,216	$—	$—	$32,216
Natural gas sales	3,053	328	—	3,381
Transportation services	23,785	5,131	—	28,916
Processing and other revenues	4,205	—	—	4,205
Total Revenues	63,259	5,459	—	68,718
Operating Costs and Expenses:				
Cost of sales and transportation services	32,307	2,697	—	35,004
Operations and maintenance	8,588	689	—	9,277
Depreciation and amortization	7,342	1,771	757	9,870
General and administrative	6,071	1,249	1	7,321
Taxes, other than income taxes	1,577	268	—	1,845
Total Operating Costs and Expenses	55,885	6,674	758	63,317
Operating Income (Loss)	7,374	(1,215)	(758)	5,401
Other (Expense) Income:				
Interest (expense) income, net	(1,422)	46	—	(1,376)
Loss on extinguishment of debt	—	—	—	—
Other income, net	1,054	16	—	1,070
Total Other (Expense) Income	(368)	62	—	(306)
Net Income (Loss)	$7,006	$(1,153)	$(758)	$5,095
Net loss attributable to noncontrolling interests	—	—	505	505
Net Income (Loss) attributable to partners	$7,006	$(1,153)	$(253)	$5,600

	Nine Months Ended September 30, 2013			
	TEP	Consolidate Trailblazer Pipeline Company LLC	Consolidate Tallgrass Pony Express Pipeline, LLC	TEP (As currently reported)
	(in thousands)			
Revenues:				
Natural gas liquids sales	$97,307	$—	$—	$97,307
Natural gas sales	7,242	837	—	8,079
Transportation services	73,446	15,997	—	89,443
Processing and other revenues	8,924	—	—	8,924
Total Revenues	186,919	16,834	—	203,753
Operating Costs and Expenses:				
Cost of sales and transportation services	94,135	7,312	—	101,447
Operations and maintenance	23,428	2,441	—	25,869
Depreciation and amortization	22,324	5,511	2,271	30,106
General and administrative	15,744	4,120	3	19,867
Taxes, other than income taxes	4,748	806	—	5,554
Total Operating Costs and Expenses	160,379	20,190	2,274	182,843
Operating Income (Loss)	26,540	(3,356)	(2,274)	20,910
Other (Expense) Income:				
Interest (expense) income, net	(10,486)	51	—	(10,435)
Loss on extinguishment of debt	(17,526)	—	—	(17,526)
Other income, net	1,822	49	—	1,871
Total Other (Expense) Income	(26,190)	100	—	(26,090)
Net Income (Loss)	350	(3,256)	(2,274)	(5,180)
Net loss attributable to noncontrolling interests	—	—	1,516	1,516
Net Income (Loss) attributable to partners	$350	$(3,256)	$(758)	$(3,664)

Formation of BNN Water Solutions, LLC

On November 26, 2013, TEP, through its wholly-owned subsidiary Tallgrass Energy Investments, LLC (“TEI”), entered into a joint venture agreement with BNN Energy LLC (“BNN”) to form Grasslands Water Services I, LLC (“GWSI”). GWSI subsequently built and began operating an intrastate water pipeline in Colorado. TEP accounted for its 50% equity interest in GWSI as an equity method investment. On May 13, 2014, TEI entered into a contribution agreement with BNN and several other parties to form a new entity known as BNN Water Solutions, LLC (“Water Solutions”). Under the terms of the contribution agreement, TEI agreed to contribute its existing 50% interest in GWSI, along with $7.6 million cash, in exchange for an 80% equity interest in Water Solutions. As part of the transaction, GWSI was renamed BNN Redtail, LLC (“Redtail”), became a subsidiary of Water Solutions, and issued preferred equity interests to TEI. Among the assets contributed by BNN and the other parties to the transaction were the other 50% interest in GWSI and a 100% equity interest in Alpha Reclaim Technology, LLC (“Alpha”), a company which sources treated wastewater from municipalities. Alpha is wholly-owned by Redtail.

Upon closing of the transaction, TEP obtained a controlling financial interest in Water Solutions and accordingly has accounted for the transaction as a step acquisition under ASC 805. On the acquisition date, TEP remeasured its previously held 50% equity interest in GWSI to its fair value of $11.9 million, recognized a gain of $9.4 million, and consolidated Water Solutions. The 20% equity interest in Water Solutions held by noncontrolling interests was recorded at its acquisition date fair value of $1.4 million. The fair values of the previously held equity interest and the noncontrolling interest were determined using a discounted cash flow based on forecasted cash flows for the business. These fair value measurements are based on significant inputs that are not observable in the market and thus represent fair value measurements categorized within Level 3 of the fair value hierarchy under ASC 820.

The following represents the fair value of assets acquired and liabilities assumed at May 13, 2014 (in thousands):

Accounts receivable	$790	
Property, plant and equipment	4,100	
Intangible assets	8,200	(1)
Accounts payable and accrued liabilities	(134	)
Distribution payable	(634	)
Net identifiable assets acquired	12,322	
Goodwill	8,573	
Net assets acquired	$20,895	

(1) The $8.2 million intangible asset acquired represents a major customer contract. See Note 8 – Goodwill and Other Intangible Assets for additional information.

At September 30, 2014, the assets acquired and liabilities assumed in the acquisition were recorded at provisional amounts based on the preliminary purchase price allocation. TEP is in the process of obtaining additional information to identify and measure all assets acquired and liabilities assumed in the acquisition within the measurement period. Such provisional amounts will be adjusted if necessary to reflect any new information about facts and circumstances that existed at the acquisition date that, if known, would have affected the measurement of these amounts.

Actual revenue and net loss attributable to TEP from Water Solutions of $3.1 million and $0.2 million, respectively, was recognized in the accompanying Condensed Consolidated Statements of Income for the period from May 13, 2014 to September 30, 2014. Pro Forma revenue and net income attributable to TEP for the nine months ended September 30, 2014 was $264.9 million and $34.9 million, respectively. No pro forma information is presented for the three and nine months ended September 30, 2013 as Water Solutions did not begin commercial operations until the first quarter of 2014.

This unaudited pro forma financial information for TEP is presented as if the acquisition of Water Solutions had been completed on January 1, 2013. The pro forma financial information is not necessarily indicative of what the actual results of operations or financial position of TEP would have been if the transactions had in fact occurred on the date or for the period indicated, nor do they purport to project the results of operations or financial position of TEP for any future periods or as of any date. The pro forma financial information does not give effect to any cost savings, operating synergies, or revenue enhancements expected to result from the transactions or the costs to achieve these cost savings, operating synergies, and revenue enhancements. The pro forma revenue and net income includes adjustments for the nine months ended September 30, 2014 to give effect to the following:

(a) Reduction in net income attributable to TEP to remove equity in earnings of GWSI recorded for the period from January 1, 2014 to May 13, 2014.

(b) Increase in revenue and net income attributable to TEP to reflect TEP's consolidated 80% equity interest in the operations of GWSI for the period from January 1, 2014 to May 13, 2014.

(c) Reduction in net income attributable to TEP to remove gain on remeasurement of previously held equity interest in GWSI.

5. Related Party Transactions

TEP has no employees. Beginning November 13, 2012, TD, through its wholly-owned subsidiary Tallgrass Operations, LLC ("Tallgrass Operations"), provided and charged TEP for all direct and indirect costs of services provided to us or incurred on our behalf including employee labor costs, information technology services, employee health and life benefits, and all other expenses necessary or appropriate to the conduct of our business. TEP recorded these costs on the accrual basis in the period in which TD incurred them. Each of the wholly-owned companies comprising TEP had an agency arrangement with TD under which TD paid costs and expenses incurred by TEP, acted as an agent for TEP, and was reimbursed by TEP for such payments.

On May 17, 2013, in connection with the closing of TEP's IPO, TEP and its general partner entered into an Omnibus Agreement with TD and certain of its affiliates, including Tallgrass Operations (the "Omnibus Agreement"). The Omnibus Agreement provides that, among other things, TEP will reimburse TD and its affiliates for all expenses they incur and payments they make on TEP's behalf, including the costs of employee and director compensation and benefits as well as the cost of the provision of certain centralized corporate functions performed by TD, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology and human resources in each case to the extent reasonably allocable to TEP.

For the calendar year 2014, TEP's annual cost reimbursements to TD for costs discussed above, are expected to be $20.4 million, inclusive of costs associated with our acquisition of Trailblazer in April 2014 and our consolidation of Water Solutions in May 2014. TEP also pays a quarterly reimbursement to TD for costs associated with being a public company. The quarterly public company reimbursement was $625,000 for the third quarter of 2014 and TEP currently expects it to remain the same through the end of 2014. However, these reimbursement amounts will be periodically reviewed and adjusted as necessary to continue to reflect reasonable allocation of costs to TEP.

The Pony Express annual reimbursement amount will be determined in the fourth quarter of 2014 after the Pony Express pipeline is placed in service. Pony Express will also reimburse TD for costs incurred on its behalf.

Due to the cash management agreement discussed in Note 2 – Summary of Significant Accounting Policies, intercompany balances at the Predecessor Entity were periodically settled and treated as equity distributions prior to the completion of the IPO on May 17, 2013 and prior to April 1, 2014 for Trailblazer. Balances lent to TD under the Pony Express cash management agreement effective September 1, 2014 are classified as related party receivables on the condensed consolidated balance sheet and will be cash settled. TEP recognized interest income from TD of $0.5 million during the three and nine months ended September 30, 2014 on the receivable balance under the Pony Express cash management agreement.

Totals of transactions with affiliated companies are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Charges to TEP: (1)				
Property, plant and equipment, net	$7,926	$319	$14,534	$5,212
Operation and maintenance	$4,701	$4,401	$13,657	$13,117
General and administrative (2)	$5,783	$7,237	$14,670	$19,531

(1) Charges to TEP include directly charged wages and salaries, other compensation and benefits, and shared services.

(2) During the three and nine months ended September 30, 2014 and 2013, TEP reimbursed TD for general and administrative expenses as discussed above, resulting in allocated amounts for general and administrative costs.

Details of balances with affiliates included in "Accounts receivable" and "Accounts payable" in the Condensed Consolidated Balance Sheets are as follows:

	September 30, 2014	December 31, 2013
	(in thousands)	
Receivables from affiliated companies:		
Tallgrass Operations, LLC	$237,537	$—
Total receivables from affiliated companies	$237,537	$—
Payables to affiliated companies:		
Tallgrass Operations, LLC	$23,579	$7,106
Rockies Express Pipeline LLC	17	31
Total payables to affiliated companies	$23,596	$7,137

Balances of gas imbalances with affiliated shippers are as follows:

	September 30, 2014	December 31, 2013
	(in thousands)	
Affiliate gas balance receivables	$31	$137
Affiliate gas balance payables	$648	$122

Pursuant to the terms of a Purchase and Sale Agreement dated August 1, 2012, TD, through August 31, 2014, reimbursed TIGT for all costs TIGT incurred with respect to the Pony Express Abandonment, as defined in Note 15 – Regulatory Matters, including, but not limited to, development costs, capital costs and related interest costs associated with the construction of certain gas facilities necessary to maintain existing natural gas service on the TIGT System (the “Replacement Gas Facilities”). The Replacement Gas Facilities are required as part of the Pony Express Abandonment in order for TIGT to continue service to existing customers after having sold approximately 430 miles of natural gas pipeline, and associated rights of way and certain other equipment, to Pony Express in 2013. For more information, see Note 15 – Regulatory Matters. Any costs incurred by TIGT subsequent to August 31, 2014 will be reimbursed directly by Pony Express.

TIGT’s expenditures for the Replacement Gas Facilities are captured in “Prepayments and other current assets” in the Condensed Consolidated Balance Sheets as they are incurred and interest is accrued until reimbursement takes place (which is typically monthly). During the nine months ended September 30, 2014 we received proceeds from TD of $69.2 million and incurred expenditures of $41.7 million. We recognized a contribution of $27.5 million from TD in our Condensed Consolidated Statement of Partners' Capital which represents the difference between the carrying amount of the Replacement Gas Facilities and the proceeds received from TD. At December 31, 2013, TEP had $17.0 million in “Prepayments and other current assets” related to this project that were cash settled by TD in the first quarter of 2014.

6. Inventory

The components of inventory at September 30, 2014 and December 31, 2013 consisted of the following:

	September 30, 2014	December 31, 2013
	(in thousands)	
Crude oil	$82,504	$—
Materials and supplies	2,461	2,137
Natural gas liquids	1,872	1,009
Gas in underground storage	4,956	2,403
Total inventory	$91,793	$5,549

In July 2014, Pony Express entered into an agreement with Shell Trading (US) Company (“Shell”) for the purchase of 800,000 barrels of crude oil for initial line fill on the Pony Express Mainline, which will be sold back to Shell in November 2014. To support the resale obligation of Pony Express, in July 2014 TD paid Shell a deposit of $20 million and issued a letter of credit for $20 million and a parent guarantee of $40 million to Shell on behalf of Pony Express. As of September 30, 2014, TEP has a liability of $86.8 million for the return of the crude oil to Shell included in "Accrued and other current liabilities," a deposit of $20 million in "Prepayments and other current assets," and a related party payable to TD of $20 million included in "Accounts payable to related parties" for the repayment of the funds deposited by TD on behalf of Pony Express on the condensed consolidated balance sheet in addition to the crude oil included in the inventory balance.

7. Property, Plant and Equipment

A summary of net property, plant and equipment by classification is as follows:

	September 30, 2014	December 31, 2013
	(in thousands)	
Natural gas pipelines	$420,658	$397,287
Processing and treating assets	239,083	209,329
General and other	31,000	26,076
Construction work in progress	1,131,991	506,378

Accumulated depreciation and amortization	(42,983)	(22,264)
Total property, plant and equipment, net	$1,779,749	$1,116,806

8. Goodwill and Other Intangible Assets

Reconciliation of Goodwill

The following table presents a reconciliation of the carrying amount of goodwill by reportable segment for the reporting period:

	Three Months Ended September 30, 2014				Three Months Ended September 30, 2013		
	Natural Gas Transportation & Logistics	Processing & Logistics		Total	Natural Gas Transportation & Logistics	Processing & Logistics	Total
		(in thousands)				(in thousands)	
Balance at beginning of period	$255,558	$87,730		$343,288	$255,100	$78,057	$333,157
Goodwill acquired	—	—		—	—	—	—
Balance at end of period	$255,558	$87,730		$343,288	$255,100	$78,057	$333,157
	Nine Months Ended September 30, 2014				Nine Months Ended September 30, 2013		
	Natural Gas Transportation & Logistics	Processing & Logistics		Total	Natural Gas Transportation & Logistics	Processing & Logistics	Total
		(in thousands)				(in thousands)	
Balance at beginning of period	$255,558	$79,157		$334,715	$255,100	$78,057	$333,157
Goodwill acquired	—	8,573	(1)	8,573	—	—	—
Balance at end of period	$255,558	$87,730		$343,288	$255,100	$78,057	$333,157

(1) The $8.6 million of goodwill was recorded in connection with the acquisition of a controlling interest in Water Solutions on May 13, 2014.

Annual Goodwill Impairment Analysis

TEP evaluates goodwill for impairment on an annual basis and whenever events or changes in circumstances necessitate an evaluation for impairment. Examples of such facts and circumstances include the excess of fair value over carrying amount in the last valuation or changes in the business environment. TEP's annual impairment testing date is August 31st. TEP evaluates goodwill for impairment at the reporting unit level, which is an operating segment as defined in the segment reporting guidance of the Codification, using either the qualitative assessment option or the two-step test approach depending on facts and circumstances of the reporting unit. If TEP, after performing the qualitative assessment, determines it is "more likely than not" that the fair value of a reporting unit is greater than its carrying amount, the two-step impairment test is unnecessary. When goodwill is evaluated for impairment using the two-step test, the carrying amount of the reporting unit is compared to its fair value in Step 1 and if the fair value exceeds the carrying amount, Step 2 is unnecessary. If the carrying amount exceeds the reporting unit's fair value, this could indicate potential impairment and Step 2 of the goodwill evaluation process is required to determine if goodwill is impaired and to measure the amount of impairment loss to recognize, if any. When Step 2 is necessary, the fair value of individual assets and liabilities is determined using valuations, or other observable sources of fair value, as appropriate. If the carrying amount of goodwill exceeds its implied fair value, the excess is recognized as an impairment loss.

TEP did not elect to apply the qualitative assessment option during our 2014 annual goodwill impairment testing, instead we proceeded directly to the two-step quantitative test. In Step 1 of the two-step quantitative test, we compared the fair value of each reporting unit with its respective book value, including goodwill, by using an income approach based on a discounted cash flow analysis. For the purposes of goodwill impairment testing, goodwill was allocated to our reporting units based on the enterprise value of each reporting unit at the date of acquisition. The fair value of each reporting unit was determined on a stand-alone basis from the perspective of a market participant and included a sensitivity analysis of the impact of changes in various assumptions. This approach required us to make long-term forecasts of future operating results and various other assumptions and estimates, the most significant of which are gross margin, operating expenses, general and administrative expenses, long-term growth rates and the weighted average cost of capital. The fair value of the reporting units was determined using significant unobservable inputs, considered Level 3 under the fair value hierarchy in the Codification. For each reporting unit, the results of the Step 1 impairment analysis indicated no potential impairment as the fair value of the reporting units was greater than their respective book values. As a result, in accordance with the Codification guidance, Step 2 of the impairment analysis was not necessary as part of the annual impairment analysis in 2014. Unpredictable events or deteriorating market or operating conditions could result in a future change to the discounted cash flow models and cause impairments in the future. We continue to monitor potential impairment indicators to determine if a triggering event occurs and will perform additional goodwill impairment analyses as necessary.

Other Intangible Assets

A summary of amortized intangible assets is as follows:

	September 30, 2014	December 31, 2013
	(in thousands)	
Pony Express oil conversion use rights	$105,973	$105,973
Redtail customer contract	8,200	—
Accumulated amortization	(7,617)	(3,406)
Intangible assets, net	$106,556	$102,567

We account for intangible assets in accordance with ASC 805, which established that an intangible asset is identifiable if it meets either the separability criterion or the contractual-legal criterion. Further, in accordance with ASC 805, contract-based intangible assets represent the value of rights that arise from contractual arrangements. Use rights such as drilling, water, air, timber cutting, and route authorities are an example of contract-based intangible assets. Intangible assets arose at Pony Express from the acquisition of rights associated with the ability and regulatory permissions to convert a section of TIGT’s natural gas pipeline, which was subsequently purchased by Pony Express, to crude oil and includes the operational and financial benefits that accrue due to those rights and the ability to make that asset more valuable (“Pony Express oil conversion use rights”). These intangible assets are amortized on a straight-line basis over a period of 35 years, the period of expected future benefit. Intangible assets arose at BNN Redtail, LLC ("Redtail") as a result of a significant customer contract with favorable market terms which was acquired as part of the Water Solutions transaction discussed in Note 4 – Acquisitions. These intangible assets are amortized on a straight-line basis over a period of 1.6 years, the remaining term of the contract at the time of acquisition. Amortization of intangible assets was approximately $2.0 million and $4.2 million for the three and nine months ended September 30, 2014, respectively, and $0.8 million and $2.3 million for the three and nine months ended September 30, 2013, respectively.

9. Risk Management

TEP occasionally enters into derivative contracts with third parties for the purpose of hedging exposures that accompany its normal business activities. TEP’s normal business activities expose it to risks associated with changes in the market price of commodities, including, among others, natural gas and crude oil. Specifically, the risks associated with changes in the market price of natural gas, include, among others (i) pre-existing or anticipated physical natural gas sales, (ii) natural gas purchases and (iii) natural gas system use and storage. TEP has elected not to apply hedge accounting and changes in the fair value of all derivative contracts are recorded in earnings in the period in which the change occurs.

Fair Value of Derivative Contracts

The following table summarizes the fair values of TEP’s derivative contracts included in the accompanying Condensed Consolidated Balance Sheets:

	Balance Sheet Location	September 30, 2014	December 31, 2013
		(in thousands)	
Energy commodity derivative contracts	Current liabilities	$44	$184

TEP had no derivative contracts in asset positions as of September 30, 2014 or December 31, 2013. As of September 30, 2014, the fair value shown for commodity contracts was comprised of derivative volumes for short fixed-price swaps totaling 0.2 Bcf.

Effect of Derivative Contracts on the Income Statement

The following table summarizes the impact of derivative contracts included in the accompanying Condensed Consolidated Statements of Income and Comprehensive Income for the three and nine months ended September 30, 2014 and 2013:

	Location of gain (loss) recognized in income on derivatives	Amount of gain (loss) recognized in income on derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2014	2013	2014	2013
		(in thousands)			
Derivatives not designated as hedging contracts:					
Energy commodity derivative contracts	Natural gas sales	$9	$(91)	$(449)	$(375)

Credit Risk

TEP has counterparty credit risk as a result of its use of derivative contracts. TEP's counterparties consist of major financial institutions. This concentration of counterparties may impact TEP's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

TEP maintains credit policies that it believes minimize its overall credit risk. These policies include (i) an evaluation of potential counterparties' financial condition (including credit ratings), (ii) collateral requirements under certain circumstances and (iii) the use of standardized agreements which allow for netting of positive and negative exposure associated with a single counterparty. Based on its policies and exposure, TEP's management does not currently anticipate a material adverse effect on TEP's financial position, results of operations, or cash flows as a result of counterparty performance.

TEP's over-the-counter swaps are entered into with counterparties outside central trading organizations such as a futures, options or stock exchange. These contracts are with financial institutions with investment grade credit ratings. While TEP enters into derivative transactions principally with investment grade counterparties and actively monitors their ratings, it is nevertheless possible that from time to time losses will result from counterparty credit risk in the future. As of September 30, 2014, the fair value of TEP's derivative contracts was a liability, resulting in no credit exposure from TEP's counterparties as of that date.

In addition, when the market value of TEP's derivative contracts with specific counterparties exceeds established limits, TEP is required to provide collateral to its counterparties, which may include posting letters of credit or placing cash in margin accounts. Accordingly, entity valuation adjustments are necessary to reflect the effect of TEP's own credit quality on the fair value of TEP's net liability position with each counterparty. The methodology to determine this adjustment is consistent with how TEP evaluates counterparty credit risk, taking into account current credit spreads for its comparative industry sector, as well as any change in such spreads since the last measurement date. As of September 30, 2014 and December 31, 2013, TEP did not have any outstanding letters of credit or cash in margin accounts in support of its hedging of commodity price risks associated with the sale of natural gas nor did TEP have margin deposits with counterparties associated with energy commodity contract positions.

Fair Value

Derivative assets and liabilities are measured and reported at fair value. Derivative contracts can be exchange-traded or over-the-counter ("OTC"). Exchange-traded derivative contracts typically fall within Level 1 of the fair value hierarchy if they are traded in an active market. TEP values exchange-traded derivative contracts using quoted market prices for identical securities.

OTC derivatives are valued using models utilizing a variety of inputs including contractual terms and commodity and interest rate curves. The selection of a particular model and particular inputs to value an OTC derivative contract depends upon the contractual terms of the instrument as well as the availability of pricing information in the market. TEP uses similar models to value similar instruments. For OTC derivative contracts that trade in liquid markets, such as generic forwards and swaps, model inputs can generally be verified and model selection does not involve significant management judgment. Such contracts are typically classified within Level 2 of the fair value hierarchy. Certain OTC derivative contracts trade in less liquid markets with limited pricing information; as such, the determination of fair value for these derivative contracts is inherently more difficult. Such contracts are classified within Level 3 of the fair value hierarchy. The valuations of these less liquid OTC derivatives are typically impacted by Level 1 and/or Level 2 inputs that can be observed in the market, as well as unobservable Level 3 inputs. Use of a different valuation model or different

valuation input values could produce a significantly different estimate of fair value. However, derivative contracts valued using inputs unobservable in active markets are generally not material to TEP’s financial statements.
When appropriate, valuations are adjusted for various factors including credit considerations. Such adjustments are generally based on available market evidence. In the absence of such evidence, management’s best estimate is used.
The following tables summarize the fair value measurements of TEP’s energy commodity derivative contracts in a liability position as of September 30, 2014 and December 31, 2013 based on the fair value hierarchy established by the Codification:

		Liability fair value measurements using		
	Total	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
	(in thousands)			
TEP as of September 30, 2014				
Energy commodity derivative contracts	$44	$—	$44	$—
TEP as of December 31, 2013				
Energy commodity derivative contracts	$184	$—	$184	$—

10. Long-term Debt
Revolving Credit Facility
TEP has a senior secured revolving credit facility with Barclays Bank PLC, as administrative agent, and a syndicate of lenders (the "Credit Agreement") which will mature on May 17, 2018. On June 25, 2014, TEP and certain of its subsidiaries entered into Amendment No. 1 (the "Amendment") to the Credit Agreement dated as of May 17, 2013. The Amendment modified certain provisions of the Credit Agreement to, among other things, (i) increase the amount of the revolving facility from $500 million to $850 million, (ii) increase the sublimit for swing line loans to $60 million, (iii) increase the sublimit for letters of credit to $75 million, (iv) increase the accordion feature to allow the Partnership to borrow up to an additional $250 million, subject to the Partnership's receipt of increased or new commitments from lenders and satisfaction of certain other conditions, and (v) reduce the applicable margin for loans by 0.25%.
The following table sets forth the outstanding borrowings, letters of credit issued, and available borrowing capacity under the revolving credit facility as of September 30, 2014 and December 31, 2013:

	September 30, 2014	December 31, 2013
	(in thousands)	
Total capacity under the revolving credit facility	$850,000	$500,000
Less: Outstanding borrowings under the revolving credit facility	(568,000)	(135,000)
Less: Letters of credit issued under the revolving credit facility	—	(654)
Available capacity under the revolving credit facility	$282,000	$364,346

The credit facility contains various covenants and restrictive provisions that, among other things, limit or restrict TEP’s ability (as well as the ability of TEP’s restricted subsidiaries) to incur or guarantee additional debt, incur certain liens on assets, dispose of assets, make certain distributions (including distributions from available cash, if a default or event of default under the credit agreement then exists or would result from making such a distribution), change the nature of TEP’s business, engage in certain mergers or make certain investments and acquisitions, enter into non-arms-length transactions with affiliates and designate certain subsidiaries as “Unrestricted Subsidiaries.” Currently, no subsidiaries have been designated as Unrestricted Subsidiaries. In addition, TEP is required to maintain a consolidated leverage ratio of not more than 4.75 to 1.00 (which will be increased to 5.25 to 1.00 for certain measurement periods following the consummation of certain acquisitions) and a consolidated interest coverage ratio of not less than 2.50 to 1.00. As of September 30, 2014, TEP is in compliance with the covenants required under the revolving credit facility.

The unused portion of the credit facility is subject to a commitment fee, which was initially 0.375%, and after June 25, 2014, ranges from 0.300% to 0.500%, based on TEP's total leverage ratio. As of September 30, 2014, the weighted average interest rate on outstanding borrowings was 2.18%.

Long-term Debt Allocated from TD

On November 13, 2012, TD entered into a credit agreement with a syndicate of lenders which included a term loan, a delayed draw term loan and a revolving credit facility. Prior to May 17, 2013, the long-term debt held by TD was guaranteed by TIGT and TMID, and $400 million of that debt was expected to be assumed by TEP in connection with the IPO. As such, $400 million of the term loan, along with the corresponding discount and deferred financing costs, was allocated to TEP as of November 13, 2012. The term loan is an obligation of TD and prior to May 17, 2013, was guaranteed by TIGT and TMID.

Upon the closing of the IPO on May 17, 2013, TEP legally assumed the previously allocated $400 million portion of the TD term loan and used a portion of the IPO proceeds, along with borrowings under TEP’s revolving credit agreement, to repay its $400 million portion of the term loan, at which time TIGT and TMID were released as guarantors of the TD debt. TEP recognized a loss on extinguishment of debt of $17.5 million during the year ended December 31, 2013 associated with the portion of deferred financing costs and unamortized discount on the amount of the TD term loan that was allocated to TEP.

Fair Value

The following table sets forth the carrying amount and fair value of TEP’s long-term debt, which is not measured at fair value in the Condensed Consolidated Balance Sheets as of September 30, 2014 and December 31, 2013, but for which fair value is disclosed:

	Fair Value				
	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total	Carrying Amount
	(in thousands)				
September 30, 2014	$—	$568,000	$—	$568,000	$568,000
December 31, 2013	$—	$135,000	$—	$135,000	$135,000

The long-term debt borrowed under the revolving credit facility is carried at amortized cost. As of September 30, 2014 and December 31, 2013, the fair value approximates the carrying amount for the borrowings under the revolving credit facility using a discounted cash flow analysis. TEP is not aware of any factors that would significantly affect the estimated fair value subsequent to September 30, 2014.

11. Partnership Equity and Distributions

Public Offering

On July 25, 2014, TEP sold 8,050,000 common units representing limited partner interests in an underwritten public offering at a price of $41.07 per unit, or $39.74 per unit net of the underwriter's discount, for net proceeds of approximately $319.6 million after deducting the underwriter's discount and offering expenses paid by TEP. TEP used the net proceeds from the offering to fund a portion of the consideration for the acquisition of a 33.3% membership interest in Pony Express as discussed in Note 4 – Acquisitions.

Distributions

TEP’s partnership agreement requires TEP to distribute its available cash, as defined below, to unitholders of record on the applicable record date within 45 days after the end of each quarter, beginning with the quarter ended June 30, 2013. TEP’s partnership agreement provides that available cash, each quarter, is first distributed to the common unitholders and the general partner on a pro rata basis until each common unitholder has received $0.2875 per unit, which amount is defined in TEP’s partnership agreement as the minimum quarterly distribution (“MQD”). During the subordination period, defined below, holders of the subordinated units are not entitled to receive a distribution of available cash until each holder of common units has received the MQD, and if the MQD is not paid for any quarter, the cumulative amount of any arrearages in the payment of the MQD from prior quarters.

The following table shows the distributions for the year ended 2013 and nine months ended September 30, 2014:

Three Months Ended	Date Paid	Distributions Limited Partners Common and Subordinated Units	General Partner Incentive Distribution Rights	General Partner General Partner Units	Total	Distributions per Limited Partner Unit	
		(in thousands, except per unit amounts)					
September 30, 2014	November 14, 2014[1]	$20,092	$1,208	$363	$21,663	$ 0.4100	
June 30, 2014	August 14, 2014	18,596	758	330	19,684	0.3800	
March 31, 2014	May 14, 2014	13,288	126	274	13,688	0.3250	
December 31, 2013	February 12, 2014	12,757	63	262	13,082	0.3150	
September 30, 2013	November 13, 2013	12,049	—	245	12,294	0.2975	
June 30, 2013	August 13, 2013	5,759	—	118	5,877	0.1422	(2)

(1) The distribution declared on October 7, 2014 for the third quarter of 2014 will be paid November 14, 2014 subsequent to the date of this Quarterly Report on 49,005,480 common units and subordinated units of record at the close of business on October 31, 2014.

(2) The distribution declared on July 18, 2013 for the second quarter of 2013 represented a prorated amount of the MQD of $0.2875 per common unit, based upon the number of days between the closing of the IPO on May 17, 2013 and June 30, 2013.

Subordinated Units

All subordinated units are currently held by TD. The principal difference between the common units and subordinated units is that in any quarter during the subordination period, holders of the subordinated units are not entitled to receive a distribution of available cash until the holders of common units have received the MQD (inclusive of any cumulative arrearages of previously unpaid MQD from previous quarters). Furthermore, subordinated unitholders are not entitled to receive arrearages from previous quarterly distributions. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units. The subordination period will end, and the subordinated units will convert to common units, on a one-for-one basis, when certain distribution milestones described in the partnership agreement have been met.

General Partner Units

As of September 30, 2014, the general partner owns a 1.7% general partner interest in TEP, which was represented by 834,391 general partner units. Under TEP's partnership agreement, the general partner may at any time, but is under no obligation to contribute additional capital to TEP in order to maintain its 2% general partner interest. As discussed in Note 4 – Acquisitions, in April 2014, in connection with TEP's acquisition of Trailblazer, the general partner contributed capital in exchange for the issuance of an additional 7,860 general partner units in order to continue to maintain its 2% general partner interest. TEP subsequently issued additional units in July 2014 and September 2014 to fund a portion of the consideration and as consideration for the acquisition of Pony Express, respectively. The general partner did not contribute additional capital to maintain its 2% general partner interest at the time of either issuance.

Incentive Distribution Rights

The general partner also owns all of the IDRs. IDRs represent the right to receive an increasing percentage (13%, 23% and 48%) of quarterly distributions of available cash from operating surplus after the MQD and the target distribution levels have been achieved. The general partner may transfer these rights separately from its general partner interest, subject to restrictions in TEP's partnership agreement.

The following discussion related to incentive distributions assumes that TEP's general partner maintains its 2% general partner interest and continues to own all of the IDRs.

If for any quarter:

- TEP has distributed available cash from operating surplus to all of the common unitholders (and during the subordination period, to the subordinated unitholders) in an amount equal to the MQD for each outstanding unit for such quarter; and

- TEP has distributed available cash from operating surplus on outstanding common units in an amount necessary to eliminate any cumulative arrearages in the payment of the MQD to common unitholders;

then, TEP will distribute additional available cash from operating surplus for that quarter among the unitholders and the general partner in the following manner:

- first, 98% to all unitholders, pro rata, and 2% to TEP's general partner, until each unitholder receives a total of $0.3048 per unit for that quarter (the "first target distribution");
- second, 85% to all unitholders, pro rata, and 15% to TEP's general partner, until each unitholder receives a total of $0.3536 per unit for that quarter (the "second target distribution");
- third, 75% to all unitholders, pro rata, and 25% to TEP's general partner, until each unitholder receives a total of $0.4313 per unit for that quarter (the "third target distribution"); and
- thereafter, 50% to all unitholders, pro rata, and 50% to TEP's general partner.

Definition of Available Cash

Available cash generally means, for any quarter, all cash and cash equivalents on hand at the end of that quarter:

- less, the amount of cash reserves established by TEP's general partner to:
- provide for the proper conduct of TEP's business (including reserves for future capital expenditures, for anticipated future credit needs subsequent to that quarter, for legal matters and for refunds of collected rates reasonably likely to be refunded as a result of a settlement or hearing related to FERC rate proceedings);
- comply with applicable law or regulation, any of TEP's debt instruments or other agreements; or
- provide funds for distributions to unitholders and to TEP's general partner for any one or more of the next four quarters (provided that TEP's general partner may not establish cash reserves for distributions if the effect of the establishment of such reserves will prevent TEP from distributing the MQD on all common units and any cumulative arrearages on such common units for the current quarter);
- plus, if TEP's general partner so determines, all or any portion of the cash on hand on the date of distribution of available cash for the quarter, including cash on hand resulting from working capital borrowings made subsequent to the end of such quarter.

Other Contributions and Distributions

During the nine months ended September 30, 2014, TEP received net contributions of $312.1 million, $27.5 million, and $5.4 million from the Predecessor Member, TD, and noncontrolling interests, respectively. Net contributions of $312.1 million from the Predecessor Member is composed of net contributions of $612.1 million relating to the cash management agreements with TD, as well as a cash distribution of $300 million of the proceeds from the issuance of the preferred membership interest to TEP from Pony Express to TD pursuant to the Pony Express Contribution and Sale Agreement. As discussed in Note 2 – Summary of Significant Accounting Policies, prior to May 17, 2013 for TIGT and TMID, prior to April 1, 2014 for Trailblazer, and prior to September 1, 2014 for Pony Express, the net amount of transfers for loans made each day through the centralized cash management system with TD, less reimbursement payments under the agency agreement described in Note 5 – Related Party Transactions, was recognized as net equity contributions or distributions during that time period. There were no equity contributions or distributions made to TD subsequent to Trailblazer's acquisition by TEP on April 1, 2014 or the acquisition of Pony Express effective September 1, 2014. The $27.5 million contribution from TD represents the difference between the carrying amount of the Replacement Gas Facilities and the proceeds received from TD, as discussed in Note 5 – Related Party Transactions. The $5.4 million contribution from noncontrolling interests represents the cash contributed to Pony Express from TD to fund the quarterly preference payment to TEP as discussed in Note 4 – Acquisitions.

During the nine months ended September 30, 2014, TEP was deemed to have made a noncash, net capital distribution of $72.9 million to the general partner, which represents the excess purchase price over the carrying value of the Trailblazer net assets acquired on April 1, 2014. Also during the nine months ended September 30, 2014, TEP was deemed to have made a capital distribution of $8.7 million to the general partner, which represents the excess purchase price, consisting of $27 million in cash and limited partner common units valued at $3.0 million issued directly to TD, over the net book value of the 1.9585% membership interest in Pony Express transferred from TD to TEP in accordance with the Pony Express Contribution and Sale Agreement. See Note 4 – Acquisitions for additional information regarding the Trailblazer and Pony Express acquisitions.

During the nine months ended September 30, 2013, net distributions from TEP Predecessor to TD were approximately $118.5 million, and included the $85.5 million to TD related to the contribution of TIGT and TMID to TEP as well as the $31.2 million net proceeds from the exercise of the underwriter’s option to purchase additional common units as part of the IPO. During the nine months ended September 30, 2013, the Trailblazer Predecessor and Pony Express Predecessor recognized net contributions from TD of $200.3 million.

12. Commitments & Contingent Liabilities

Leases

Pony Express entered into a lease agreement with Deeprock Development, LLC (“Deeprock”), an unconsolidated affiliate of TD, on November 7, 2012. The agreement is for the use by Pony Express of storage capacity at the Deeprock tank storage facility near Cushing, Oklahoma and will commence on the first day of the first month immediately following the day the pipeline becomes operational. The lease has a five year term. Lease payments will have two components; a fixed charge of $1.3 million per month and a volumetric charge for barrels delivered in excess of a base volume. Pony Express will also make an upfront payment of $10.9 million, of which $4.6 million was paid in 2013 and the remainder of which will be paid when the lease goes into effect. The upfront payments are recorded as “Deferred charges and other assets” on the accompanying condensed consolidated balance sheets and will be amortized over the lease term. Pony Express has the right to extend the term of the lease for additional periods of five or two years, not to exceed a total of twenty years from when the lease commences.

On August 26, 2014, Pony Express entered into a lease agreement with Tallgrass Sterling Terminal, LLC ("Sterling"), an indirect wholly-owned subsidiary of TD. The agreement is for the use by Pony Express of storage capacity at the Sterling tank storage facility in northeast Colorado for a five year term beginning on the first day of the first month immediately following the day that the Northeast Colorado Lateral expansion is placed in service, which is expected to be in the first half of 2015. Pony Express has the right to extend the term of the lease for additional periods of five years, not to exceed a total of twenty years from the commencement of the lease agreement. Lease payments will have two components; a fixed charge of $0.9 million per month and a volumetric charge for barrels delivered in excess of a

base volume.
TEP has no other significant lease agreements in place.
13. Net Income per Limited Partner Unit
The Partnership’s net income is allocated to the general partner and the limited partners, including the holders of the subordinated units, in accordance with their respective ownership percentages, after giving effect to incentive distributions paid to the general partner. Basic and diluted net income per limited partner unit is calculated by dividing limited partners’ interest in net income, less general partner incentive distributions, by the weighted average number of outstanding limited partner units during the period.
TEP computes earnings per unit using the two-class method for Master Limited Partnerships as prescribed in the FASB guidance. The two-class method requires that securities that meet the definition of a participating security be considered for inclusion in the computation of basic earnings per unit. Under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed under the terms of the partnership agreement, regardless of whether the general partner has discretion over the amount of distributions to be made in any particular period, whether those earnings would actually be distributed during a particular period from an economic or practical perspective, or whether the general partner has other legal or contractual limitations on its ability to pay distributions that would prevent it from distributing all of the earnings for a particular period.
TEP calculates net income available to limited partners based on the distributions pertaining to the current period’s net income. After adjusting for the appropriate period’s distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the general partner and limited partners in accordance with the contractual terms of the partnership agreement and as further prescribed in the FASB guidance under the two-class method.
The two-class method does not impact TEP’s overall net income or other financial results; however, in periods in which aggregate net income exceeds its aggregate distributions for such period, it will have the impact of reducing net income per limited partner unit. This result occurs as a larger portion of TEP’s aggregate earnings, as if distributed, is allocated to the incentive distribution rights of the general partner, even though TEP makes distributions on the basis of available cash and not earnings. In periods in which TEP’s aggregate net income does not exceed its aggregate distributions for such period, the two-class method does not have any impact on our calculation of earnings per limited partner unit.
Basic earnings per unit is computed by dividing net earnings attributable to unitholders by the weighted average number of units outstanding during each period. Diluted earnings per unit reflects the potential dilution of common equivalent units that could occur if equity participation units are converted into common units.
As the IPO was completed on May 17, 2013, no income from the period from January 1, 2013 to May 16, 2013 is allocated to the limited partner units that were issued on May 17, 2013 and all income for such period was allocated to the general partner or predecessor operations. All net income or loss from Trailblazer prior to its acquisition on April 1, 2014 and Pony Express prior to its acquisition effective September 1, 2014 is allocated to predecessor operations in the table below. Historical earnings of transferred businesses for periods prior to the date of the common control drop-down transaction are solely those of the general partner and, therefore we have appropriately excluded any allocation to the limited partner units when determining net income available to common and subordinated unitholders. We present the financial results of any transferred business prior to the drop down transaction date in the line item "Predecessor operations interest in net (income) loss" in the table below.
The following table illustrates the Partnership’s calculation of net income per common and subordinated unit for the three and nine months ended September 30, 2014 and 2013:

	Three Months Ended September 30, 2014		Three Months Ended September 30, 2013	
	(in thousands, except per unit amounts)			
Net income	$11,253		$5,095	
Net loss attributable to noncontrolling interests	191		505	
Net income attributable to partners	11,444		5,600	
Predecessor operations interest in net loss	1,134		1,406	
General partner interest in net income	(1,435	)	(140	)
Net income available to common and subordinated unitholders	$11,143		$6,866	

Basic net income per common and subordinated unit	$0.24	$0.17
Diluted net income per common and subordinated unit	$0.23	$0.17
Basic average number of common and subordinated units outstanding	46,855	40,500
Equity Participation Unit equivalent units	1,093	363
Diluted average number of common and subordinated units outstanding	47,948	40,863

	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	Period from January 1, 2013 to May 16, 2013	Period from May 17, 2013 to September 30, 2013
	(in thousands, except per unit amounts)			
Net income (loss)	$42,597	$(5,180)	$5,049	$(10,229)
Net loss attributable to noncontrolling interests	1,256	1,516	761	755
Net income (loss) attributable to partners	43,853	(3,664)	5,810	(9,474)
Predecessor operations interest in net (income) loss	(1,508)	4,014	1,172	2,842
General partner interest in net (income) loss	(2,912)	(6,849)	(6,982)	133
Net income (loss) available to common and subordinated unitholders	$39,433	$(6,499)	$—	$(6,499)
Basic net income (loss) per common and subordinated unit	$0.92	$(0.16)		$(0.16)
Diluted net income (loss) per common and subordinated unit	$0.90	$(0.16)		$(0.16)
Basic average number of common and subordinated units outstanding	42,770	40,417		40,417
Equity Participation Unit equivalent units	1,001	—		—
Diluted average number of common and subordinated units outstanding	43,771	40,417		40,417

14. Equity-Based Compensation

Long-term Incentive Plan

Effective May 13, 2013, the general partner adopted a Long-term Incentive Plan ("LTIP") pursuant to which awards in the form of unrestricted units, restricted units, equity participation units, options, unit appreciation rights or distribution equivalent rights may be granted to employees, consultants, and directors of the general partner and its affiliates who perform services for or on behalf of TEP or its affiliates, including TD. Vesting and forfeiture requirements are at the discretion of the board of directors of the general partner at the time of the grant.

The LTIP limits the number of units that may be delivered pursuant to vested awards to 10,000,000 common units. Common units canceled, forfeited or withheld to satisfy exercise prices or tax withholding obligations will be available for delivery pursuant to other awards. The plan is administered by the board of directors of TEP's general partner or a committee thereof, which is referred to as the plan administrator.

The plan administrator may terminate or amend the LTIP at any time with respect to any units for which a grant has not yet been made. The plan administrator also has the right to alter or amend the LTIP or any part of the plan from time to time, including increasing the number of units that may be granted subject to the requirements of the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would materially reduce the rights or benefits of the participant without the consent of the participant. The LTIP will expire on the earliest of (i) the date common units are no longer available under the plan for grants, (ii) termination of the plan by the plan administrator or (iii) May 13, 2023.

Equity Participation Units

On June 26, 2013, TEP's general partner approved the grant of up to 1.5 million equity participation units ("EPUs") for issuance to employees and 177,500 EPUs to certain Section 16 officers under the LTIP. Vesting of the EPUs granted to employees is contingent upon the Pony Express Mainline being placed into service and will generally occur in two parts, with one-third vesting on the later of the Pony Express Mainline in-service date or May 13, 2015, and the remaining two-thirds vesting on the later of the Pony Express Mainline in-service date or May 13, 2017. The Pony Express Mainline was placed in service in October 2014. Beginning in the second quarter of 2014, new EPUs granted will vest on terms and conditions as approved by the general partner or the plan administrator.

The EPU grants under the LTIP plan are measured at their grant date fair value. The EPUs granted are non-participating with respect to distributions, therefore the grant date fair value is discounted from the grant date fair value of TEP's common units for the present value of the expected future distributions during the vesting period. Total equity-based compensation cost related to the EPU grants of approximately \$2.8 million and \$7.4 million was recognized during the three and nine months ended September 30, 2014. Of the total compensation cost, \$1.5 million and \$3.7 million was recognized as compensation expense at TEP for the three and nine months ended September 30, 2014 and the remainder was allocated to TD. Total equity-based compensation cost related to the EPU grants of approximately \$2.0 million and \$2.1 million was recognized during the three and nine months ended September 30, 2013. As of September 30, 2014, \$15.7 million of total compensation cost related to non-vested EPUs is expected to be recognized over a weighted average period of 2.2 years, a portion of which will be charged to TD.

The following table summarizes the changes in the EPUs outstanding for the three and nine months ended September 30, 2014:

	Three Months Ended September 30, 2014		Three Months Ended September 30, 2013	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value
Beginning of period	1,567,500	$ 18.66	1,490,000	$ 17.49
Granted	1,500	37.10	5,500	18.92
Forfeited	(30,750)	(17.49)	(29,500)	(17.49)
End of period	1,538,250	$ 18.71	1,466,000	$ 17.49
	Nine Months Ended September 30, 2014		Nine Months Ended September 30, 2013	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value
Beginning of period	1,474,250	$ 17.54	—	$ —
Granted	144,000	30.07	1,495,500	17.49
Forfeited	(80,000)	(17.53)	(29,500)	(17.49)
End of period	1,538,250	$ 18.71	1,466,000	$ 17.49

15. Regulatory Matters
TIGT
Pony Express Abandonment – FERC Docket CP12-495
On August 6, 2012, TIGT filed an application to: (1) abandon for FERC purposes approximately 430 miles of mainline natural gas pipeline facilities, along with associated rights of way and other related equipment (collectively, the "Pony Express Assets"), and the natural gas service therefrom, by transferring those assets to Pony Express, which will convert the Pony Express Assets into crude oil pipeline facilities; and (2) construct and operate the Replacement Gas Facilities in order to continue service to existing natural gas firm transportation customers following the proposed conversion. This project is referred to as the “Pony Express Abandonment.” The FERC abandonment does not constitute an abandonment for accounting purposes. Pursuant to the terms of the Purchase and Sale Agreement filed with the FERC and cited by the FERC in approving the Pony Express Abandonment, Pony Express is required to reimburse TIGT for the net book value of the Pony Express Assets plus other TIGT incurred costs required to construct the Replacement Gas Facilities and to arrange substitute gas transportation services to certain TIGT shippers.
The Pony Express Abandonment and completion of the Pony Express Project by Pony Express will re-deploy existing pipeline assets to meet the growing market need to transport oil supplies while at the same time continuing to operate TIGT’s natural gas transportation facilities to meet all current and expected needs of its natural gas customers. By a FERC order issued September 12, 2013, TIGT was granted authorization to abandon the Pony Express Assets and construct the Replacement Gas Facilities. On October 7, 2013 TIGT commenced the mobilization of personnel and equipment for the construction of the Replacement Gas Facilities necessary to complete the Pony Express Abandonment to continue service to existing TIGT customers. In December 2013, TIGT removed the Pony Express Assets from gas service and sold those assets to Pony Express. On May 1, 2014, TIGT commenced commercial service through all of the Replacement Gas Facilities, with the exception of Units 3 and 4 at the Tescott Compressor Station. Service through Units 3 and 4 at the Tescott Compressor Station commenced on May 30, 2014.
Trailblazer
2013 Rate Case Filing - Docket No. RP13-1031
On July 1, 2013, Trailblazer made a rate filing with FERC pursuant to Section 4 of the Natural Gas Act in Docket No. RP13-1031. In this filing, Trailblazer proposed an overall cost of service of $25.7 million, an increase of the base rates, rolled-in base and fuel rates, an overall rate of return of 10.94% and new depreciation rates. On July 31, 2013, FERC issued an order accepting Trailblazer’s filing and suspending the filed tariff rates, subject to refund, for the full statutorily permitted five-month suspension period and setting certain issues for hearing. FERC resolved the non-rate aspects of Trailblazer’s rate case in an order dated December 30, 2013.
In conjunction with this filing for rolled-in fuel rates, Trailblazer elected to not seek recovery of unrecovered fuel costs incurred prior to January 1, 2014. Consequently, Trailblazer has recognized expenses related to unrecovered fuel costs of $578,000 for the period from November 13, 2012 to December 31, 2012, $6.0 million for period from January 1, 2012 to November 12, 2012 and $8.4 million during the year ended December 31, 2013.
On January 22, 2014, Trailblazer, FERC’s Trial Staff, and the active parties in the pipeline’s general rate case finalized a settlement in principle resolving the pending rate issues, including: (i) establishing transportation rates, as well as fuel and lost and unaccounted for charges; (ii) providing a limited profit sharing arrangement for certain revenues earned from interruptible and short-term firm transport; and (iii) setting the minimum and maximum time that can elapse before Trailblazer’s next rate case at FERC. Trailblazer filed a motion with FERC’s Chief Administrative Law Judge to accept the settlement rates on an interim basis (“Interim Rates”) while the participants finalized a definitive settlement. The Chief Administrative Law Judge accepted the Interim Rates effective February 1, 2014. On February 24, 2014, Trailblazer filed an uncontested offer of settlement (“Stipulation and Agreement”) among active party shippers. The Stipulation and Agreement established the Interim Rates as final settlement rates effective February 1, 2014, subject to the issuance of refunds to certain shippers for January 2014 transportation services and revised fuel and lost and unaccounted for rates, effective July 1, 2014. On March 11, 2014, the Presiding Administrative Law Judge certified the Stipulation and Agreement. On May 29, 2014, FERC approved the Stipulation and Agreement. On June 30, 2014, Trailblazer filed tariff sheets to implement the Stipulation and Agreement effective July 1, 2014. Estimated refunds were reserved from revenues recorded in January 2014. On July 1, 2014, Trailblazer submitted

refunds to its customers for amounts collected in excess of amounts that would have been collected under the Settlement Rates, with interest, and on July 18, 2014, filed a report of refunds with the FERC. The FERC issued orders accepting the tariff sheets with the requested effective date of July 1, 2014 and accepting the refund report filing on July 25, 2014 and August 7, 2014, respectively.

Pony Express
On September 19, 2014 Pony Express filed for initial local Non Contract Rates as well as an initial Rules and Regulations in accordance with the Interstate Commerce Act to be effective starting on October 1, 2014. Local Contract Tariff rates were filed on October 29, 2014. Joint Contract Tariff rates for oil received into the Pony Express pipeline system from the Belle Fourche Pipeline were filed on October 16, 2014. It is not known at this time when Hiland Pipeline Company will file the Joint Contract Tariff rates for movements between its system and Pony Express.
Other Regulatory Matters
There are currently no proceedings challenging the rates of Pony Express, TIGT, or Trailblazer. Regulators, as well as shippers, do have rights, under circumstances prescribed by applicable regulations, to challenge the rates that TIGT and Trailblazer charge. TEP can provide no assurance that current rates will remain unchallenged. Any successful challenge could have a material, adverse effect on TEP’s future earnings and cash flows.
16. Legal and Environmental Matters
Legal
In addition to the matters discussed below, TEP is a defendant in various lawsuits arising from the day-to-day operations of its business. Although no assurance can be given, TEP believes, based on its experiences to date, that the ultimate resolution of such routine items will not have a material adverse impact on its business, financial position, results of operations or cash flows.
TEP has evaluated claims in accordance with the accounting guidance for contingencies that it deems both probable and reasonably estimable and, accordingly, has aggregate reserves for legal claims of approximately $0.6 million and $0.3 million as of September 30, 2014 and December 31, 2013, respectively.
TIGT
Prairie Horizon
On July 3, 2014, Prairie Horizon Agri-Energy LLC ("Prairie Horizon") filed an action in the District Court of Phillips County, Kansas against TIGT seeking damages from an alleged intrusion of foreign material and oil from TIGT into Prairie Horizon's ethanol plant. Prairie Horizon asserts that this intrusion caused substantial damage to Prairie Horizon's ethanol production facilities and resulted in corresponding business income losses. Prairie Horizon also claims that the intrusion was a violation of TIGT's FERC Gas Tariff. Prairie Horizon alleges that it has suffered damages in the amount of approximately $2.0 million. TIGT believes Prairie Horizon's claims are without merit and plans to vigorously contest all of the claims in this matter.
System Failures
On May 4, 2013 and on June 13, 2013, a failure occurred on two separate segments of the TIGT pipeline system; one in Kimball County, Nebraska and one in Goshen County, Wyoming. Both failures resulted in the release of natural gas. Both lines were promptly brought back into service and neither failure caused any known injuries, fatalities, fires or evacuations. The costs to repair or replace the damaged section in Kimball County, Nebraska were not material. In February 2014, TEP communicated to PHMSA that TEP’s investigation of the pipeline involved in the Kimball County failure is complete and TEP intends to restore pressure to full maximum allowable operating pressure. TEP is currently working with PHMSA to develop a plan to close the Corrective Action Order received from PHMSA and expects the cost of remaining remediation activities related to the Goshen County failure to approximate $0.8 million.
Environmental
TEP is subject to a variety of federal, state and local laws that regulate permitted activities relating to air and water quality, waste disposal, and other environmental matters. TEP believes that compliance with these laws will not have a material adverse impact on its business, cash flows, financial position or results of operations. However, there can be no assurances that future events, such as changes in existing laws, the promulgation of new laws, or the development of new facts or conditions will not cause TEP to incur significant costs. TEP has environmental accruals of $5.4 million and $5.0 million at September 30, 2014 and December 31, 2013, respectively.
TMID
Casper Plant, U.S. EPA Notice of Violation

In August 2011, the U.S. EPA and the WDEQ conducted an inspection of the Leak Detection and Repair ("LDAR") Program at the Casper Gas Plant in Wyoming. In September 2011, TMID received a letter from the U.S. EPA alleging violations of the Standards of Performance of Equipment Leaks for Onshore Natural Gas Processing Plant requirements under the Clean Air Act. TMID received a letter from the U.S. EPA concerning settlement of this matter in April 2013 and received additional settlement communications from the U.S. EPA and Department of Justice beginning in July 2014. Settlement negotiations are continuing, including attempted resolution of more recently identified LDAR issues.

Casper Mystery Bridge Superfund Site

The Casper Gas Plant is part of the Mystery Bridge Road/U.S. Highway 20 Superfund Site also known as Casper Mystery Bridge Superfund Site. Remediation work at the Casper Gas Plant has been completed and TEP has requested that the portion of the site attributable to TEP be delisted from the National Priorities List.

17. Reporting Segments

TEP's operations are located in the United States. During the third quarter of 2014, management revised TEP's segment reporting structure to reflect the acquisition of a membership interest in Pony Express. As a result, TEP is now organized into three reporting segments: (1) Natural Gas Transportation & Logistics, (2) Crude Oil Transportation & Logistics, and (3) Processing & Logistics.

Natural Gas Transportation & Logistics

The Natural Gas Transportation & Logistics segment is engaged in ownership and operation of FERC-regulated interstate natural gas pipelines and integrated natural gas storage facilities that provide services to on-system customers (such as third-party LDCs), industrial users and other shippers. As discussed in Note 2 – Summary of Significant Accounting Policies, results for prior periods have been recast to reflect the operations of Trailblazer.

Crude Oil Transportation & Logistics

The Crude Oil Transportation & Logistics segment is engaged in ownership and construction of a FERC-regulated crude oil pipeline to serve the Bakken Shale and other nearby oil producing basins. The Pony Express Mainline was placed in service in October 2014. The Crude Oil Transportation & Logistics segment also includes the construction of the Northeast Colorado Lateral, which will interconnect with the Pony Express Mainline just east of Sterling, Colorado. The Northeast Colorado Lateral is expected to be placed in service during the first half of 2015.

Processing & Logistics

The Processing & Logistics segment is engaged in ownership and operation of natural gas processing, treating and fractionation facilities that produce NGLs and residue gas that is sold in local wholesale markets or delivered into pipelines for transportation to additional end markets, as well as water business services provided primarily to the oil and gas exploration and production industry.

Corporate and Other

Corporate and Other includes corporate overhead costs incurred subsequent to the IPO on May 17, 2013 that are not directly associated with the operations of TEP's reportable segments, such as interest and fees associated with TEP's revolving credit facility, public company costs reimbursed to TD, and equity-based compensation expense.

These segments are monitored separately by management for performance and are consistent with internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for their respective operations.

TEP considers Adjusted EBITDA as its primary segment performance measure as TEP believes it is the most meaningful measure to assess TEP's financial condition and results of operations as a public entity. Adjusted EBITDA, a non-GAAP measure, is defined as net income excluding the impact of interest, income taxes, depreciation and amortization, non-cash income or loss related to derivative instruments, non-cash long-term compensation expense, impairment losses, gains or losses on asset or business disposals or acquisitions, gains or losses on the repurchase, redemption or early retirement of debt, and earnings from unconsolidated investments, but including the impact of distributions from unconsolidated investments.

The following tables set forth TEP's segment information for the periods indicated:

	Three Months Ended September 30, 2014			Three Months Ended September 30, 2013		
	Total Revenue	Inter-Segment (in thousands)	External Revenue	Total Revenue	Inter-Segment (in thousands)	External Revenue
Natural Gas Transportation & Logistics	$32,090	$—	$32,090	$31,893	$(151)	$31,742
Processing & Logistics	57,863	—	57,863	36,976	—	36,976
Total revenue	$89,953	$—	$89,953	$68,869	$(151)	$68,718

	Nine Months Ended September 30, 2014			Nine Months Ended September 30, 2013		
	Total Revenue	Inter-Segment (in thousands)	External Revenue	Total Revenue	Inter-Segment (in thousands)	External Revenue
Natural Gas Transportation & Logistics	$103,076	$—	$103,076	$94,754	$(521)	$94,233
Processing & Logistics	158,976	—	158,976	109,520	—	109,520
Total revenue	$262,052	$—	$262,052	$204,274	$(521)	$203,753

	Three Months Ended September 30, 2014			Three Months Ended September 30, 2013		
	Total Adjusted EBITDA (in thousands)	Inter-Segment	External Adjusted EBITDA	Total Adjusted EBITDA (in thousands)	Inter-Segment	External Adjusted EBITDA
Natural Gas Transportation & Logistics	$17,152	$(1,430)	$15,722	$14,305	$(151)	$14,154
Crude Oil Transportation & Logistics	(22)	—	(22)	(1)	—	(1)
Processing & Logistics	8,615	—	8,615	3,644	151	3,795
Corporate and other	(625)	—	(625)	(632)	—	(632)
Reconciliation to Net Income:						
Interest expense, net			1,414			1,376
Depreciation and amortization expense, net of noncontrolling interest			9,568			9,365
Non-cash (gain) loss related to derivative instruments			(395)			112
Non-cash compensation expense			1,475			863
Distributions from unconsolidated investment			184			—
Net Income (Loss) attributable to partners			$11,444			$5,600

	Nine Months Ended September 30, 2014			Nine Months Ended September 30, 2013		
	Total Adjusted EBITDA (in thousands)	Inter-Segment	External Adjusted EBITDA	Total Adjusted EBITDA (in thousands)	Inter-Segment	External Adjusted EBITDA
Natural Gas Transportation & Logistics	$52,080	$(4,015)	$48,065	$39,247	$(521)	$38,726
Crude Oil Transportation & Logistics	(22)	—	(22)	(1)	—	(1)
Processing & Logistics	23,722	—	23,722	15,713	521	16,234
Corporate and other	(1,875)	—	(1,875)	(939)	—	(939)
Reconciliation to Net Income:						
Interest expense, net			4,848			10,435
Depreciation and amortization expense, net of noncontrolling interest			26,246			28,592
Loss on extinguishment of debt			—			17,526
Non-cash (gain) loss related to derivative instruments			(140)			183
Non-cash compensation expense			3,724			948
Distributions from unconsolidated investment			1,464			—
Equity in earnings of unconsolidated investment			(717)			—
Gain on remeasurement of unconsolidated investment			(9,388)			—
Net Income (Loss) attributable to partners			$43,853			$(3,664)

	Total Assets	
	September 30, 2014 (in thousands)	December 31, 2013
Natural Gas Transportation & Logistics	$717,234	$734,145
Crude Oil Transportation & Logistics	1,567,055	566,156
Processing & Logistics	344,240	326,599
Corporate and other	7,006	4,513
Total assets	$2,635,535	$1,631,413

18. Subsequent Events

Pony Express Placed In Service

On October 8, 2014, TEP announced that line fill for the Pony Express Mainline was completed and the pipeline had been placed in commercial service.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The historical financial statements included in this Quarterly Report reflect the combined results of operations of Tallgrass Interstate Gas Transmission, LLC ("TIGT") and Tallgrass Midstream, LLC ("TMID"), which we refer to collectively as "our Predecessor." Historical periods have been recast to reflect the operations of Trailblazer Pipeline Company LLC ("Trailblazer"), which was acquired on April 1, 2014, and Tallgrass Pony Express Pipeline, LLC ("Pony Express"), of which TEP acquired a 33.3% membership interest effective September 1, 2014.

In connection with our initial public offering, on May 17, 2013 Tallgrass Development, LP ("TD") contributed to us its equity interests in our Predecessor. The following discussion analyzes the financial condition and results of operations of our Predecessor. In certain circumstances and for ease of reading we discuss the financial results of the Predecessor as being "our" financial results during historic periods, although TIGT and TMID were owned by TD from November 13, 2012 until May 17, 2013, Trailblazer was owned by TD from November 13, 2012 to March 31, 2014, and Pony Express was wholly-owned by TD from November 13, 2012 to August 31, 2014. As used in this Quarterly Report, unless the context otherwise requires, "we," us," our," the "Partnership," "TEP" and similar terms refer to Tallgrass Energy Partners, LP, together with its consolidated subsidiaries.

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the unaudited condensed consolidated financial statements and related notes thereto included elsewhere in this Quarterly Report. Additionally, the following discussion should be read in conjunction with the audited financial statements and notes thereto, the related "Management's Discussion and Analysis of Financial Condition and Results of Operations," the discussion of "Risk Factors" and the discussion of TEP's "Business" in our Annual Report on Form 10-K for the year ended December 31, 2013 (our "2013 Form 10-K").

A reference to a "Note" herein refers to the accompanying Notes to Condensed Consolidated Financial Statements contained in Item 1.—Financial Statements. In addition, please read "Cautionary Statement Regarding Forward-Looking Statements" and "Risk Factors" for information regarding certain risks inherent in our business.

Cautionary Statement Regarding Forward-Looking Statements

This Quarterly Report and the documents incorporated by reference herein contain forward-looking statements concerning our operations, economic performance and financial condition. Forward-looking statements give our current expectations, contain projections of results of operations or of financial condition, or forecasts of future events. Words such as "could," "will," "may," "assume," "forecast," "position," "predict," "strategy," "expect," "intend," "plan," "esti "believe," "project," "budget," "potential," or "continue," and similar expressions are used to identify forward-looking statements. Without limiting the generality of the foregoing, forward-looking statements contained in this Quarterly Report include our expectations of plans, strategies, objectives, growth and anticipated financial and operational performance, including guidance regarding our and Tallgrass Development's infrastructure programs, revenue projections, capital expenditures and tax position. Forward-looking statements can be affected by assumptions used or by known or unknown risks or uncertainties. Consequently, no forward-looking statements can be guaranteed.

A forward-looking statement may include a statement of the assumptions or bases underlying the forward-looking statement. We believe that we have chosen these assumptions or bases in good faith and that they are reasonable. However, when considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this Quarterly Report and our 2013 Form 10-K. Actual results may vary materially. You are cautioned not to place undue reliance on any forward-looking statements. You should also understand that it is not possible to predict or identify all such factors and should not consider the following list to be a complete statement of all potential risks and uncertainties. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statements include:

- our ability to complete and integrate acquisitions from TD or from third parties, including the recently completed Trailblazer acquisition and the acquisition of a 33.3% membership interest in Pony Express;
- changes in general economic conditions;
- competitive conditions in our industry;
- actions taken by third-party operators, processors and transporters;
- the demand for natural gas processing, storage and transportation services, and crude oil transportation services;
- our ability to successfully implement our business plan;

- our ability to complete internal growth projects on time and on budget;
- the price and availability of debt and equity financing;

- the availability and price of natural gas and crude oil, and other fuel derived from both, to the consumer compared to the price of alternative and competing fuels;
- competition from the same and alternative energy sources;
- energy efficiency and technology trends;
- operating hazards and other risks incidental to transporting crude oil and transporting, storing and processing natural gas;
- natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- interest rates;
- labor relations;
- large customer defaults;
- changes in tax status;
- the effects of existing and future laws and governmental regulations;
- the effects of future litigation; and
- certain factors discussed elsewhere in this Quarterly Report.

Forward-looking statements speak only as of the date on which they are made. While we may update these statements from time to time, we are not required to do so other than pursuant to the securities laws.

Overview

We are a publicly traded, growth-oriented limited partnership formed to own, operate, acquire and develop midstream energy assets in North America. We currently provide natural gas transportation and storage services for customers in the Rocky Mountain and Midwest regions of the United States through our TIGT and Trailblazer systems. We provide processing services for customers in Wyoming through TMID at our Casper and Douglas natural gas processing and our West Frenchie Draw natural gas treating facilities and we provide water business services to customers through Water Solutions. We also provide crude oil transportation to customers in Wyoming and the surrounding region, including servicing the Bakken production area of North Dakota and eastern Montana, through our 33.3% ownership interest in Pony Express. Our operations are strategically located in and provide services to certain key United States hydrocarbon basins, including the Denver-Julesburg Basin, the Powder River Basin, the Wind River Basin and the Anadarko Basin and the Niobrara, Mississippi Lime and Bakken shale formations.

We intend to leverage our relationship with TD and utilize the significant experience of our management team to execute our growth strategy of acquiring midstream assets from TD and third parties, increasing utilization of our existing assets and expanding our systems through construction of additional assets.

Effective September 1, 2014, we closed on the acquisition of a 33.3% membership interest in Pony Express. As discussed in Note 4 – Acquisitions, the terms of the transaction provide TEP a minimum quarterly preference payment of $16.65 million through the quarter ending September 30, 2015 (pro-rated to approximately $5.4 million for the quarter ending September 30, 2014) with distributions thereafter shared in accordance with the terms of the Second Amended and Restated Limited Liability Company Agreement of Pony Express.

Our reportable business segments are:

- Natural Gas Transportation & Logistics—the ownership and operation of FERC-regulated interstate natural gas pipelines and integrated natural gas storage facilities;
- Crude Oil Transportation & Logistics—the ownership and operation of the Pony Express crude oil pipeline system; and
- Processing & Logistics—the ownership and operation of natural gas processing, treating and fractionation facilities that produce NGLs and residue gas that is sold in local wholesale markets or delivered into pipelines for transportation to additional end markets, as well as water business services provided primarily to the oil and gas exploration and production industry.

Recent Developments

Pony Express Placed In Service

On October 8, 2014, we announced that line fill for the Pony Express Mainline was completed and the pipeline had been placed in commercial service.

How We Evaluate Our Operations

We evaluate our results using, among other measures, contract mix and volumes, operating costs and expenses, Adjusted EBITDA and distributable cash flow. Adjusted EBITDA and distributable cash flow are non-GAAP measures and are defined below.

Contract Mix and Volumes

Our results are driven primarily by the volume of natural gas transportation and storage capacity under firm contracts, the volume of natural gas that we process and the fees assessed for such services.

Operating Costs and Expenses

The primary components of our operating costs and expenses that we evaluate include cost of sales and transportation services, operations and maintenance and general and administrative costs. Our operating expenses are driven primarily by expenses related to the operation, maintenance and growth of our asset base.

Adjusted EBITDA and Distributable Cash Flow

Adjusted EBITDA and distributable cash flow are non-GAAP supplemental financial measures that management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies, may use to assess:

- our operating performance as compared to other publicly traded partnerships in the midstream energy industry, without regard to historical cost basis or, in the case of Adjusted EBITDA, financing methods;
- the ability of our assets to generate sufficient cash flow to make distributions to our unitholders;
- our ability to incur and service debt and fund capital expenditures; and
- the viability of acquisitions and other capital expenditure projects and the returns on investment of various expansion and growth opportunities.

We believe that the presentation of Adjusted EBITDA and distributable cash flow provides useful information to investors in assessing our financial condition and results of operations. Adjusted EBITDA and distributable cash flow should not be considered alternatives to net income, operating income, net cash provided by operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP, nor should Adjusted EBITDA and distributable cash flow be considered alternatives to available cash, operating surplus, distributions of available cash from operating surplus or other definitions in our partnership agreement. Adjusted EBITDA and distributable cash flow have important limitations as analytical tools because they exclude some but not all items that affect net income and net cash provided by operating activities. Additionally, because Adjusted EBITDA and distributable cash flow may be defined differently by other companies in our industry, our definition of Adjusted EBITDA and distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

Non-GAAP Financial Measures

We define Adjusted EBITDA as net income excluding the impact of interest, income taxes, depreciation and amortization, non-cash income or loss related to derivative instruments, non-cash long-term compensation expense, impairment losses, gains or losses on asset or business disposals or acquisitions, gains or losses on the repurchase, redemption or early retirement of debt, and earnings from unconsolidated investments, but including the impact of distributions from unconsolidated investments. We also use distributable cash flow, which we define as Adjusted EBITDA, plus preferred distributions received from Pony Express in excess of its distributable cash flow attributable to our net interest, less cash interest expense and maintenance capital expenditures, to analyze our performance. As discussed in the "Overview" section above, TEP receives a minimum quarterly preference payment from Pony Express for the period from closing of the transaction through September 30, 2015. To the extent that Pony Express does not have sufficient distributable cash flow to cover this preference payment, TD is required to contribute cash to Pony Express to fund the excess preference payment. The cash received from TD to fund the minimum quarterly preference payment in excess of distributable cash flow from Pony Express is considered distributable cash flow at

TEP.

Neither Adjusted EBITDA nor distributable cash flow will be impacted by changes in working capital balances that are reflected in operating cash flow. Distributable cash flow and Adjusted EBITDA are not presentations made in accordance with GAAP.The following table presents a reconciliation of Adjusted EBITDA to net income and net cash provided by operating activities and a reconciliation of distributable cash flow to net cash provided by operating activities, the most directly comparable GAAP financial measures, for each of the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Reconciliation of Adjusted EBITDA to Net Income				
Net Income (Loss) attributable to partners	$11,444	$5,600	$43,853	$(3,664)
Add:				
Interest expense, net of noncontrolling interest	1,414	1,376	4,848	10,435
Depreciation and amortization expense, net of noncontrolling interest	9,568	9,365	26,246	28,592
Loss on extinguishment of debt	—	—	—	17,526
Non-cash (gain) loss related to derivative instruments	(395)	112	(140)	183
Non-cash compensation expense	1,475	863	3,724	948
Distributions from unconsolidated investment	184	—	1,464	—
Gain on remeasurement of unconsolidated investment	—	—	(9,388)	—
Less:				
Equity in earnings of unconsolidated investment	—	—	(717)	—
Adjusted EBITDA	$23,690	$17,316	$69,890	$54,020
Reconciliation of Adjusted EBITDA and Distributable Cash Flow to Net Cash Provided by Operating Activities				
Net cash provided by operating activities	$16,119	$18,856	$47,244	$50,342
Add:				
Interest expense, net of noncontrolling interest	1,414	1,376	4,848	10,435
Other, including changes in operating working capital	6,157	(2,916)	17,798	(6,757)
Adjusted EBITDA	$23,690	$17,316	$69,890	$54,020
Add:				
Pony Express preferred distributions in excess of distributable cash flow attributable to Pony Express	5,429	—	5,429	—
Less:				
Maintenance capital expenditures	(4,182)	(7,533)	(7,654)	(11,504)
Cash interest cost	(1,008)	(1,559)	(3,875)	(2,322)
Distributable Cash Flow attributable to predecessor operations	966	3,237	(3,086)	3,631
Distributable Cash Flow	$24,895	$11,461	$60,704	$43,825

The following table presents a reconciliation of Adjusted EBITDA by segment to segment operating income, the most directly comparable GAAP financial measure, for each of the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Reconciliation of Adjusted EBITDA to Operating Income in the Natural Gas Transportation & Logistics Segment (1)				
Operating income	$10,791	$5,773	$32,075	$14,395
Add:				

Depreciation and amortization expense, net of noncontrolling interest	6,025	7,464	17,745	22,910
Non-cash (gain) loss related to derivative instruments	(395)	112	(140)	183
Other income	731	956	2,400	1,759
Segment Adjusted EBITDA	$17,152	$14,305	$52,080	$39,247
Reconciliation of Adjusted EBITDA to Operating Income in the Crude Oil Transportation & Logistics Segment [(1)]				
Operating loss	$(822)	$(758)	$(2,336)	$(2,274)
Add:				
Depreciation and amortization expense, net of noncontrolling interest	253	252	757	757
Adjusted EBITDA attributable to noncontrolling interests	547	505	1,557	1,516
Segment Adjusted EBITDA	$(22)	$(1)	$(22)	$(1)
Reconciliation of Adjusted EBITDA to Operating Income in the Processing & Logistics Segment [(1)]				
Operating income	$5,141	$1,874	$14,459	$10,667
Add:				
Depreciation and amortization expense, net of noncontrolling interest	3,290	1,649	7,744	4,925
Distributions from unconsolidated investment	184	121	1,464	121
Adjusted EBITDA attributable to noncontrolling interests	—	—	55	—
Segment Adjusted EBITDA	$8,615	$3,644	$23,722	$15,713
Total Segment Adjusted EBITDA	$25,745	$17,948	$75,780	$54,959
Public company costs	(625)	(632)	(1,875)	(939)
Elimination of intersegment activity	(1,430)	—	(4,015)	—
Total Adjusted EBITDA	$23,690	$17,316	$69,890	$54,020

(1) Segment results as presented represent total operating income and Adjusted EBITDA, including intersegment activity, for the Natural Gas Transportation & Logistics, Crude Oil Transportation & Logistics, and Processing & Logistics segments. For reconciliations to the consolidated financial data, see Note 17 – Reporting Segments to the accompanying consolidated financial statements.

Results of Operations

The following provides a summary of our consolidated results of operations for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands, except operating data)			
Revenues:				
Natural gas liquids sales	$47,321	$32,216	$132,557	$97,307
Natural gas sales	1,809	3,381	9,330	8,079
Transportation services	30,745	28,916	95,418	89,443
Processing and other revenues	10,078	4,205	24,747	8,924
Total Revenues	89,953	68,718	262,052	203,753
Operating Costs and Expenses:				
Cost of sales and transportation services	49,096	35,004	144,921	101,447
Operations and maintenance	9,961	9,277	28,029	25,869
Depreciation and amortization	10,071	9,870	27,905	30,106
General and administrative	7,448	7,321	21,221	19,867
Taxes, other than income taxes	1,797	1,845	5,392	5,554
Total Operating Costs and Expenses	78,373	63,317	227,468	182,843
Operating Income	11,580	5,401	34,584	20,910
Other (Expense) Income:				
Interest expense, net	(1,058)	(1,376)	(4,492)	(10,435)
Gain on remeasurement of unconsolidated investment	—	—	9,388	—
Loss on extinguishment of debt	—	—	—	(17,526)
Equity in earnings of unconsolidated investment	—	—	717	—
Other income, net	731	1,070	2,400	1,871
Total Other (Expense) Income	(327)	(306)	8,013	(26,090)
Net Income (Loss)	11,253	5,095	42,597	(5,180)
Net loss attributable to noncontrolling interests	191	505	1,256	1,516
Net Income (Loss) attributable to partners	11,444	5,600	43,853	(3,664)
Other Financial Data [(1)]				
Adjusted EBITDA	$23,690	$17,316	$69,890	$54,020
Operating Data				
Operating Data (Mmcf/d):				
Transportation firm contracted capacity	1,497	1,399	1,532	1,392
Natural gas processing inlet volumes	153	120	147	128

(1) For more information regarding Adjusted EBITDA and a reconciliation of Adjusted EBITDA to its most directly comparable GAAP measure, please see “Non-GAAP Financial Measures” above.

Three Months Ended September 30, 2014 Compared to the Three Months Ended September 30, 2013

Revenues. Total revenues were $90.0 million for the three months ended September 30, 2014, compared to $68.7 million for the three months ended September 30, 2013, which represents an increase of $21.2 million, or 31%, in total revenues. Revenue in the Natural Gas Transportation & Logistics segment increased $0.2 million, or 1%, while revenues in the Processing & Logistics segment increased $20.9 million, or 56%. There were no revenues in the Crude Oil Transportation & Logistics segment for the three months ended September 30, 2014 or 2013.

Operating costs and expenses. Operating costs and expenses were $78.4 million for the three months ended September 30, 2014 compared to $63.3 million for the three months ended September 30, 2013, which represents an increase of $15.1 million, or 24%. The increase in operating costs and expenses is a result of increased costs of $17.6 million in the Processing & Logistics segment primarily driven by increased cost of sales and transportation services of $15.4 million and higher depreciation and amortization of $1.6 million, partially offset by decreased costs of $4.8 million in the Natural Gas Transportation & Logistics segment primarily driven by decreased cost of sales and transportation services of $2.9 million and lower depreciation and amortization of $1.4 million. Operating costs and expenses in the Crude Oil Transportation & Logistics segment were consistent for the three months ended September 30, 2014 compared to the three months ended September 30, 2013.

Interest (expense) income, net. Interest expense of $1.1 million for the three months ended September 30, 2014 was primarily composed of interest and fees associated with TEP's revolving credit facility, partially offset by interest income of $0.5 million on the cash balance swept to TD under the Pony Express cash management agreement. Interest expense of $1.4 million for the three months ended September 30, 2013 primarily represents interest and fees associated with TEP's revolving credit facility.

Other income (expense), net. Other income (expense), net typically includes rental income, income earned from certain customers related to the capital costs we incurred to connect these customers to our system, the allowance for funds used in construction at our regulated entities, and other noncash gains and losses. Other income for the three months ended September 30, 2014 was $0.7 million compared to $1.1 million for the three months ended September 30, 2013.

Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013

Revenues. Total revenues were $262.1 million for the nine months ended September 30, 2014, compared to $203.8 million for the nine months ended September 30, 2013, which represents a $58.3 million, or 29% increase in total revenues. Revenue in the Natural Gas Transportation & Logistics segment increased $8.3 million, or 9%, while revenues in the Processing & Logistics segment increased $49.5 million, or 45%. There were no revenues in the Crude Oil Transportation & Logistics segment for the nine months ended September 30, 2014 or 2013.

Operating costs and expenses. Operating costs and expenses were $227.5 million for the nine months ended September 30, 2014 compared to $182.8 million for the nine months ended September 30, 2013, which represents an increase of $44.6 million, or 24%. The increase in operating costs and expenses is a result of increased costs of $45.7 million in the Processing & Logistics segment primarily driven by higher costs of sales and operations and maintenance expenses as well as increased depreciation and amortization primarily related to the Water Solutions assets which were consolidated during the second quarter of 2014, partially offset by decreased costs of $9.4 million in the Natural Gas Transportation & Logistics segment primarily driven by lower depreciation and amortization as well as decreased cost of sales and operations and maintenance expenses.

Interest (expense) income, net. Interest expense of $4.5 million for the nine months ended September 30, 2014 was primarily composed of interest and fees associated with TEP's revolving credit facility. Interest expense of $10.4 million for the nine months ended September 30, 2013 primarily represents the interest expense related to the $400 million term loan allocated from TD, which was legally assumed by TEP and repaid upon closing of the IPO on May 17, 2013, as well as interest and fees associated with TEP's revolving credit facility.

Gain on remeasurement of unconsolidated investment. Gain on remeasurement of unconsolidated investment of $9.4 million for the nine months ended September 30, 2014 was related to the remeasurement to fair value of our original 50% equity investment in Grasslands Water Services I, LLC ("GWSI") in connection with TEP's consolidation of the Water Solutions business on May 13, 2014.

Loss on extinguishment of debt. Loss on extinguishment of debt of $17.5 million for the nine months ended September 30, 2013 represents the loss associated with the write off of deferred financing costs and unamortized discounts associated with the repayment of debt allocated from TD.

Equity in earnings of unconsolidated investment. Equity in earnings of unconsolidated investment of $0.7 million for the nine months ended September 30, 2014 was related to our investment in GWSI prior to TEP's consolidation of the Water Solutions business on May 13, 2014.

Other income (expense), net. Other income (expense), net typically includes rental income, income earned from certain customers related to the capital costs we incurred to connect these customers to our system, the allowance for funds used in construction at our regulated entities, and other noncash gains and losses. Other income for the nine months ended September 30, 2014 was $2.4 million compared to $1.9 million for the nine months ended September 30, 2013.

The following provides a summary of our Natural Gas Transportation & Logistics segment results of operations for the periods indicated:

Segment Financial Data - Natural Gas Transportation & Logistics [(1)]	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
	(in thousands)			
Revenues:				
Natural gas sales	$1,302	$2,822	$7,440	$4,772
Transportation services	30,745	29,067	95,418	89,964
Processing and other revenues	43	4	218	18
Total revenues	32,090	31,893	103,076	94,754
Operating costs and expenses:				
Cost of sales and transportation services	2,667	5,581	16,137	17,328
Operations and maintenance	6,699	6,325	19,396	19,451
Depreciation and amortization	6,025	7,464	17,745	22,910
General and administrative	4,191	4,982	12,574	15,351
Taxes, other than income taxes	1,717	1,768	5,149	5,319
Total operating costs and expenses	21,299	26,120	71,001	80,359
Operating income	$10,791	$5,773	$32,075	$14,395
Segment Adjusted EBITDA	$17,152	$14,305	$52,080	$39,247

(1) Segment results as presented represent total revenue and Adjusted EBITDA, including intersegment activity. For reconciliations to the consolidated financial data, see Note 17 – Reporting Segments to the accompanying consolidated financial statements.

Three Months Ended September 30, 2014 Compared to the Three Months Ended September 30, 2013

Revenues. Natural Gas Transportation & Logistics segment revenues were $32.1 million for the three months ended September 30, 2014, compared to $31.9 million for the three months ended September 30, 2013, which represents a $0.2 million, or 1% increase in segment revenues. The increase in segment revenues was driven by a $1.7 million increase in transportation services revenue primarily due to increased fuel reimbursements, partially offset by a $1.5 million decrease in natural gas sales due to decreased volumes.

Operating costs and expenses. Operating costs and expenses in the Natural Gas Transportation & Logistics segment were $21.3 million for the three months ended September 30, 2014 compared to $26.1 million for the three months ended September 30, 2013, which represents a decrease of $4.8 million, or 18%.

Cost of sales and transportation services decreased $2.9 million, or 52%, in the three months ended September 30, 2014 when compared to the same period in the prior year, primarily driven by decreased fuel costs in 2014 as a result of the Trailblazer rate case settlement.

Operations and maintenance costs increased $0.4 million, or 6%, in the three months ended September 30, 2014 when compared to the same period in the prior year, primarily driven by increased costs associated with repairs and maintenance activities in 2014, partially offset by decreased costs associated with integrity work in the third quarter of 2014 compared to 2013.

Depreciation and amortization decreased $1.4 million, or 19%, in the three months ended September 30, 2014 when compared to the same period in the prior year, primarily driven by the sale of the Pony Express Assets in the fourth quarter of 2013 and the decreased depreciation rates included in the Trailblazer rate case settlement in the second quarter of 2014.

General and administrative costs decreased $0.8 million, or 16%, in the three months ended September 30, 2014 when compared to the same period in the prior year, primarily due to the decrease in costs allocated to Trailblazer by TEP in periods subsequent to our acquisition on April 1, 2014 as compared to the costs allocated to Trailblazer by TD prior to April 1, 2014.

Taxes, other than income taxes, were comparable during the three months ended September 30, 2014 and the same period in the prior year.

Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013

Revenues. Natural Gas Transportation & Logistics segment revenues were $103.1 million for the nine months ended September 30, 2014, compared to $94.8 million for the nine months ended September 30, 2013, which represents a $8.3 million, or 9% increase in segment revenues. The increase in segment revenues was primarily driven by a $5.5 million increase in transportation services revenue driven by increased volumes at Trailblazer and fuel reimbursements at TIGT and a $2.7 million increase in natural gas sales driven by higher prices and volumes.

Operating costs and expenses. Operating costs and expenses in the Natural Gas Transportation & Logistics segment were $71.0 million for the nine months ended September 30, 2014 compared to $80.4 million for the nine months ended September 30, 2013, which represents a decrease of $9.4 million, or 12%.

Cost of sales and transportation services decreased $1.2 million, or 7%, in the nine months ended September 30, 2014 when compared to the same period in the prior year, primarily driven by decreased fuel costs in 2014 as a result of the Trailblazer rate case settlement, partially offset by increased fuel reimbursements at TIGT.

Operations and maintenance costs were comparable during the nine months ended September 30, 2014 and the same period in the prior year.

Depreciation and amortization decreased $5.2 million, or 23%, in the nine months ended September 30, 2014 when compared to the same period in the prior year, primarily driven by the sale of the Pony Express Assets in the fourth quarter of 2013 and the decreased depreciation rates included in the Trailblazer rate case settlement in the second quarter of 2014.

General and administrative costs decreased $2.8 million, or 18%, in the nine months ended September 30, 2014 when compared to the same period in the prior year, primarily due to the decrease in costs allocated to Trailblazer by TEP in periods subsequent to our acquisition on April 1, 2014 as compared to the costs allocated by TD prior to April 1, 2014.

Taxes, other than income taxes, were comparable during the nine months ended September 30, 2014 and the same period in the prior year.

The following provides a summary of our Crude Oil Transportation & Logistics segment results of operations for the periods indicated:

Segment Financial Data - Crude Oil Transportation & Logistics [1]	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
	(in thousands)			
Depreciation and amortization	$757	$757	$2,271	$2,271
General and administrative	65	1	65	3
Taxes, other than income taxes	—	—	—	—
Total operating costs and expenses	822	758	2,336	2,274
Operating loss	$(822)	$(758)	$(2,336)	$(2,274)
Segment Adjusted EBITDA	$(22)	$(1)	$(22)	$(1)

(1) Segment results as presented represent total revenue and Adjusted EBITDA, including intersegment activity. For reconciliations to the consolidated financial data, see Note 17 – Reporting Segments to the accompanying consolidated financial statements.

Three Months Ended September 30, 2014 Compared to the Three Months Ended September 30, 2013

Operating costs and expenses. Operating costs and expenses in the Crude Oil Transportation & Logistics segment were $0.8 million for the three months ended September 30, 2014 compared to $0.8 million for the three months ended September 30, 2013, and consist primarily of the amortization of the Pony Express oil conversion use rights.

Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013

Operating costs and expenses. Operating costs and expenses in the Crude Oil Transportation & Logistics segment were $2.3 million for the nine months ended September 30, 2014 compared to $2.3 million for the nine months ended September 30, 2013, and consist primarily of the amortization of the Pony Express oil conversion use rights.

The following provides a summary of our Processing & Logistics segment results of operations for the periods indicated:

Segment Financial Data - Processing & Logistics [1]	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Revenues:				
Natural gas liquids sales	$47,321	$32,216	$132,557	$97,307
Natural gas sales	507	559	1,890	3,307
Processing and other revenues	10,035	4,201	24,529	8,906
Total revenues	57,863	36,976	158,976	109,520
Operating costs and expenses:				
Cost of sales and transportation services	44,999	29,574	124,769	84,640
Operations and maintenance	3,262	2,952	8,633	6,418
Depreciation and amortization	3,289	1,649	7,889	4,925
General and administrative	1,092	850	2,983	2,635
Taxes, other than income taxes	80	77	243	235
Total operating costs and expenses	52,722	35,102	144,517	98,853
Operating income	$5,141	$1,874	$14,459	$10,667
Segment Adjusted EBITDA	$8,615	$3,644	$23,722	$15,713

(1) Segment results as presented represent total revenue and Adjusted EBITDA, including intersegment activity. For reconciliations to the consolidated financial data, see Note 17 – Reporting Segments to the accompanying consolidated financial statements.

Three Months Ended September 30, 2014 Compared to the Three Months Ended September 30, 2013

Revenues. Processing & Logistics segment revenues were $57.9 million for the three months ended September 30, 2014, compared to $37.0 million for the three months ended September 30, 2013, which represents a $20.9 million, or 56% increase in segment revenues. The increase in segment revenues was primarily due to increased NGL sales of $15.1 million as a result of higher volumes processed and a 5% increase in average NGL prices, increased processing fees of $3.6 million driven by the conversion of two significant customers from percent of proceeds contracts to fee based contracts, and revenue of $2.2 million from Water Solutions, which was consolidated in May 2014.

Operating costs and expenses. Operating costs and expenses in the Processing & Logistics segment were $52.7 million for the three months ended September 30, 2014 compared to $35.1 million for the three months ended September 30, 2013, which represents an increase of $17.6 million, or 50%.

Cost of sales and transportation services increased $15.4 million, or 52%, in the three months ended September 30, 2014 when compared to the same period in the prior year, primarily driven by an increase of $9.8 million in NGL producer settlements as a result of increased volumes processed and a 5% increase in average NGL prices, increased NGL marketing settlements of $5.2 million driven increased volumes processed with a major customer and higher prices, and increased fuel expense of $1.8 million.

Operations and maintenance costs increased $0.3 million, or 11%, in the three months ended September 30, 2014 when compared to the same period in the prior year, primarily driven by costs attributable to Water Solutions, which was consolidated in May 2014.

Depreciation and amortization increased $1.6 million, or 99%, in the three months ended September 30, 2014 when compared to the same period in the prior year, primarily driven by depreciation and amortization of $1.3 million from the Water Solutions fixed and intangible assets consolidated in May 2014 and asset additions as a result of expansion activities that were substantially completed in the third quarter of 2013.

General and administrative costs increased $0.2 million, or 28%, in the three months ended September 30, 2014 when compared to the same period in the prior year, primarily driven by costs associated with Water Solutions, which was consolidated in May 2014.

Taxes, other than income taxes, were comparable during the three months ended September 30, 2014 and the same period in the prior year.

Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013

Revenues. Processing & Logistics segment revenues were $159.0 million for the nine months ended September 30, 2014, compared to $109.5 million for the nine months ended September 30, 2013, which represents a $49.5 million, or 45% increase in segment revenues. The increase in segment revenues was primarily due to a $35.3 million increase in NGL sales driven by increased volumes processed and a 14% increase in average NGL prices, a $12.5 million increase in processing fees driven by the conversion of two significant customers from percent of proceeds contracts to fee based contracts, and revenue of $3.1 million from Water Solutions, which was consolidated in May 2014. These increases were partially offset by decreased natural gas sales of $1.4 million due to lower volumes.

Operating costs and expenses. Operating costs and expenses in the Processing & Logistics segment were $144.5 million for the nine months ended September 30, 2014 compared to $98.9 million for the nine months ended September 30, 2013, which represents an increase of $45.7 million, or 46%.

Cost of sales and transportation services increased $40.1 million, or 47%, in the nine months ended September 30, 2014 when compared to the same period in the prior year, primarily driven by an increase of $31.6 million in NGL producer settlements as a result of increased volumes processed under contracts converted to fee based as discussed above and a 14% increase in average NGL prices, and increased NGL marketing settlements of $9.7 million driven increased volumes processed with a major customer and higher prices.

Operations and maintenance costs increased $2.2 million, or 35%, in the nine months ended September 30, 2014 when compared to the same period in the prior year, primarily driven by $0.9 million of operations and maintenance costs attributable to Water Solutions, which was consolidated in May 2014, $0.6 million in environmental reserves recorded in 2014, and $0.4 million of increased costs associated with testing and treatment resulting from high water content of gas processed during the period.

Depreciation and amortization increased $3.0 million, or 60%, in the nine months ended September 30, 2014 when compared to the same period in the prior year, primarily driven by depreciation and amortization of $2.0 million from the Water Solutions fixed and intangible assets acquired in May 2014 and $1.0 million from asset additions as a result of expansion activities that were substantially completed in the third quarter of 2013.

General and administrative costs increased $0.3 million, or 13%, in the nine months ended September 30, 2014 when compared to the same period in the prior year, primarily driven by costs associated with Water Solutions.

Taxes, other than income taxes, in the nine months ended September 30, 2014 were consistent with those incurred during the same period in the prior year.

Liquidity and Capital Resources Overview

Our primary sources of liquidity for the three months ended September 30, 2014 were proceeds from the issuance of common units, borrowings under our revolving credit facility, and cash generated from operations. We expect our sources of liquidity in the future to include:

- cash generated from our operations;
- borrowing capacity available under our revolving credit facility; and
- future issuances of additional partnership units and debt securities.

We believe that cash on hand, cash generated from operations and availability under our credit facility will be adequate to meet our operating needs, our planned short-term capital and debt service requirements and our planned cash distributions to unitholders. We believe that future internal growth projects or potential acquisitions will be funded primarily through a combination of borrowings under our credit facility and issuances of debt and equity securities.

Our total liquidity as of September 30, 2014 and December 31, 2013 was as follows:

	September 30, 2014	December 31, 2013
	(in thousands)	
Cash on hand	$885	$—
Total capacity under the revolving credit facility	850,000	500,000
Less: Outstanding borrowings under the revolving credit facility	(568,000)	(135,000)

Less: Letters of credit issued under the revolving credit facility	—	(654)
Available capacity under the revolving credit facility	282,000	364,346
Total liquidity	$282,885	$364,346

Revolving Credit Facility

We have a senior secured revolving credit facility with Barclays Bank PLC, as administrative agent, and a syndicate of lenders (the "Credit Agreement") which will mature on May 17, 2018. On June 25, 2014, TEP and certain of its subsidiaries entered into Amendment No. 1 (the "Amendment") to the Credit Agreement dated as of May 17, 2013. The Amendment modifies certain provisions of the Credit Agreement to, among other things, (i) increase the amount of the revolving facility from $500 million to $850 million, (ii) increase the sublimit for swing line loans to $60 million, (iii) increase the sublimit for letters of credit to $75 million, (iv) increase the accordion feature to allow the Partnership to borrow up to an additional $250 million, subject to the Partnership's receipt of increased or new commitments from lenders and satisfaction of certain other conditions, and (v) reduce the applicable margin for loans by 0.25%.

The credit facility contains various covenants and restrictive provisions that, among other things, limit or restrict our ability (as well as the ability of our restricted subsidiaries) to incur or guarantee additional debt, incur certain liens on assets, dispose of assets, make certain distributions (including distributions from available cash, if a default or event of default under the credit agreement then exists or would result from making such a distribution), change the nature of our business, engage in certain mergers or make certain investments and acquisitions, enter into non arms-length transactions with affiliates and designate certain subsidiaries as “Unrestricted Subsidiaries.” Currently, no subsidiaries have been designated as Unrestricted Subsidiaries. In addition, we are required to maintain a consolidated leverage ratio of not more than 4.75 to 1.00 (which will be increased to 5.25 to 1.00 for certain measurement periods following the consummation of certain acquisitions) and a consolidated interest coverage ratio of not less than 2.50 to 1.00. As of September 30, 2014, TEP is in compliance with the covenants required under the revolving credit facility.

The unused portion of the credit facility is subject to a commitment fee, which was initially 0.375%, and after June 25, 2014, ranges from 0.300% to 0.500%, based on our total leverage ratio. As of September 30, 2014, the weighted average interest rate on outstanding borrowings was 2.18%.

Public Offering

On July 25, 2014, TEP sold 8,050,000 common units representing limited partner interests in an underwritten public offering at a price of $41.07 per unit, or $39.74 per unit net of the underwriter's discount, for net proceeds of approximately $319.6 million after deducting the underwriter's discount and offering expenses paid by TEP. TEP used the net proceeds from the offering to fund a portion of the consideration for the acquisition of a 33.3% membership interest in Pony Express.

Working Capital

Working capital is the amount by which current assets exceed current liabilities. As of September 30, 2014, we had a working capital surplus of $125.5 million compared to a working capital deficit of $127.0 million at December 31, 2013, which represents a increase in working capital of $252.5 million.

Our working capital requirements have been, and we expect will continue to be, primarily driven by changes in accounts receivable and accounts payable. Factors impacting changes in accounts receivable and accounts payable could include the timing of collections from customers and payments to suppliers, as well as the level of spending for capital expenditures and changes in the market prices of energy commodities that we buy and sell in the normal course of business. The overall increase in working capital from December 31, 2013 to September 30, 2014 was primarily attributable to an increase of $237.5 million in receivables from related parties resulting from the Pony Express cash balance swept to TD under the cash management agreement, an increase of $86.2 million in inventory driven by the purchase of crude oil line fill at Pony Express, and a decrease of $26.8 million in accounts payable driven by a decrease in construction accruals at Pony Express, partially offset by an increase of $88.8 million in other accrued liabilities primarily related to the obligation to return the crude oil line fill at Pony Express under the Shell agreement.

A material adverse change in operations or available financing under our revolving credit facility could impact our ability to fund our requirements for liquidity and capital resources in the future.

Cash Flows

The following table and discussion presents a summary of our cash flow for the periods indicated:

	Nine Months Ended September 30, 2014	2013
	(in thousands)	
Net cash provided by (used in):		
Operating activities	$47,244	$50,342
Investing activities	$(1,099,084)	$(237,360)
Financing activities	$1,052,725	$187,638

Operating Activities. Cash flows provided by operating activities were $47.2 million and $50.3 million for the nine months ended September 30, 2014 and 2013, respectively. The decrease in net cash flows provided by operating activities of $3.1 million was primarily driven by an increase in net cash outflows for changes in working capital, primarily due to the decrease in accounts payable associated with construction activities at Pony Express. These cash outflows were partially offset by the increase in operating results in nine months ended September 30, 2014 compared to the nine months ended September 30, 2013, as well as other operating cash outflows during the nine months ended September 30, 2013 related to the deferred lease payment at Pony Express.

Investing Activities. Cash flows used in investing activities were $1.1 billion and $237.4 million for the nine months ended September 30, 2014 and 2013, respectively. During the nine months ended September 30, 2014, net cash used in investing activities were driven by capital expenditures of $642.2 million, primarily due to construction of the Pony Express Mainline and Northeast Colorado Lateral expansion project, as well as the capacity expansion projects at TMID and other expansion projects at Trailblazer, cash outflows of $270.0 million associated with the related party loan to TD under the Pony Express cash management agreement, and cash outflows of $150.0 million, $7.6 million, and $27.0 million for the acquisitions of equity interests in Trailblazer, Water Solutions and Pony Express, respectively.

In the nine months ended September 30, 2013, net cash used in investing activities was driven by $237.1 million in capital expenditures, consisting primarily of spending on the Pony Express Mainline and capacity expansion and efficiency upgrade projects at TMID, and to a lesser extent, capital expenditures at TIGT.

Financing Activities. Cash flows provided by financing activities were $1,052.7 million for the nine months ended September 30, 2014 compared to cash flows provided by financing activities of $187.6 million for the nine months ended September 30, 2013. Financing cash inflows for the nine months ended September 30, 2014 were primarily driven by net contributions from Predecessor Member of $312.1 million, the proceeds from net borrowings under the revolving credit facility of $433.0 million, net proceeds of $319.6 million from the issuance of 8,050,000 common units in a public offering which closed on July 25, 2014, a contribution from TD of $27.5 million representing the difference between the carrying amount of the Replacement Gas Facilities and the proceeds received from TD, and contributions from noncontrolling interest of $5.4 million, which represents the contribution from TD to Pony Express to fund the minimum quarterly preference payment made to TEP under the terms of the Pony Express Contribution and Sale Agreement. These cash inflows were partially offset by distributions to TEP unitholders of $46.5 million.Cash flows provided by financing activities were $187.6 million for the nine months ended September 30, 2013 and consisted primarily of net cash inflows of $290.5 million from the completion of our IPO on May 17, 2013, net borrowings under our revolving credit facility of $226.0 million, and contributions from TD to Pony Express and Trailblazer of $197.5 million and $2.7 million, respectively. These cash inflows were partially offset by the repayment of $400.0 million of debt assumed from TD, net distributions to TD of $118.5 million prior to the closing of our IPO on May 17, 2013, distributions to unitholders of $5.9 million, and payments for deferred financing costs of $5.2 million.

Distributions

We intend to pay quarterly distributions at or above the amount of the MQD, which is $0.2875 per unit. As of October 28, 2014, we had a total of 49,839,871 common, subordinated and general partner units outstanding, which equates to an aggregate MQD of approximately $14.3 million per quarter and approximately $57.3 million per year. We do not have a legal obligation to pay distributions except as provided in our partnership agreement. A distribution of $0.41 per unit for the three months ended September 30, 2014 was declared on October 7, 2014 and will be paid on November 14, 2014 to unitholders of record on October 31, 2014.

Capital Requirements

Our business is capital-intensive, requiring significant investment to maintain and improve existing assets. We expect approximately $153.3 million for capital expenditures for the remainder of 2014, of which $148.7 million is expected for the Pony Express Mainline and Northeast Colorado Lateral construction, $1.7 million is expected for other expansion projects, $2.7 million is expected for maintenance capital expenditures, and $0.2 million is expected for the Gas Replacement Facilities and other costs associated with the Pony Express Abandonment.

Contractual Obligations

Pony Express has lease commitments for storage capacity at the Deeprock tank storage facility near Cushing, Oklahoma and the Sterling tank storage facility in northeast Colorado, each for a five year initial term, with total annual commitments of approximately $26.4 million. For additional detail, see Note 12 – Commitments & Contingent Liabilities to the condensed consolidated financial statements.

In addition, as of September 30, 2014, Pony Express has committed $42.6 million for capital expenditures relating to the Pony Express mainline and Northeast Colorado Lateral expansion construction for the remainder of 2014 and during 2015.

There have been no other material changes in our contractual obligations as reported in our 2013 Form 10-K.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Critical Accounting Policies and Estimates

The critical accounting policies and estimates used in the preparation of our condensed consolidated financial statements are set forth in our 2013 Form 10-K for the year ended December 31, 2013 and have not changed.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

The profitability of our processing contracts that include keep whole or percent of proceeds components is affected by volatility in prevailing NGL and natural gas prices. As of September 30, 2014 approximately 87% of our reserved capacity was subject to fee-based contracts, with the remaining 13% subject to percent of proceeds or keep whole contracts, a notable shift toward fee-based contracts as compared to approximately 66% fee-based contracts and approximately 34% of percent of proceeds or keep whole contracts as of December 31, 2013. We do not currently hedge the commodity exposure in our processing contracts and we do not expect to in the foreseeable future. Our Processing & Logistics segment comprised approximately 36% and 34% of our Adjusted EBITDA for the three and nine months ended September 30, 2014.

We have a limited amount of direct commodity price exposure related to crude oil collected as part of our contractual pipeline loss allowance on the Pony Express Pipeline. We do not currently hedge this commodity exposure.

We also have a limited amount of direct commodity price exposure related to natural gas collected related to electrical compression costs and lost and unaccounted for gas on the TIGT System. Historically, we have entered into derivative contracts with third parties for a substantial majority of the gas we expect to collect during the current year for the purpose of hedging our commodity price exposures. We expect to continue these hedging activities for the foreseeable future. As of September 30, 2014, we had natural gas swaps outstanding with a notional volume of approximately 0.2 Bcf short, representing a portion of the natural gas that is expected to be sold by our Natural Gas Transportation and Logistics segment through the end of 2014. The fair value of these swaps was a liability of approximately $44,000 at September 30, 2014.

We measure the risk of price changes in our natural gas swaps utilizing a sensitivity analysis model. The sensitivity analysis measures the potential income or loss (i.e., the change in fair value of the derivative instruments) based upon a hypothetical 10% movement in the underlying quoted market prices. In addition to these variables, the fair value of each portfolio is influenced by fluctuations in the notional amounts of the instruments and the discount rates used to determine the present values. We enter into derivative contracts solely for the purpose of mitigating the risks that accompany certain of our business activities and, therefore, both the sensitivity analysis model and the change in the market value of our outstanding derivative contracts are offset largely by changes in the value of the underlying physical natural gas sales. A hypothetical 10% increase in the natural gas price forward curve would result in a decrease of approximately $0.1 million in the net fair value of our derivative instruments for the quarter ended

September 30, 2014 as a result of our hedging program. For the purpose of determining the change in fair value associated with the hypothetical natural gas price increase scenario, we have assumed a parallel shift in the forward curve through the end of 2014.

Our sensitivity analysis represents an estimate of the reasonably possible gains and losses that would be recognized on the natural gas derivative contracts (including fixed price swaps and basis swaps) assuming hypothetical movements in future market prices and is not necessarily indicative of actual results that may occur. It does not represent the maximum possible loss or any expected loss that may occur, since actual future gains and losses may differ from those estimated. Actual gains and losses may differ from estimates due to actual fluctuations in market prices, operating exposures and the timing thereof, as well as changes in the notional volumes of our outstanding derivatives during the year.

The Commodity Futures Trading Commission ("CFTC") has promulgated regulations to implement Dodd-Frank's changes to the Commodity Exchange Act, including the definition of commodity-based swaps subject to those regulations. The CFTC regulations are intended to implement new reporting and record keeping requirements related to those swap transactions and a mandatory clearing and exchange-execution regime for various types, categories or classes of swaps, subject to certain exemptions, including the trade-option and end-user exemptions. Although we anticipate that most, if not all, of our swap transactions should qualify for an exemption to the clearing and exchange-execution requirements, we will still be subject to record keeping and reporting requirements. Other changes to the Commodity Exchange Act made as a result of the Dodd-Frank Act and the CFTC's implementing regulations could significantly increase the cost of entering into new swaps.

Interest Rate Risk

As described in "Liquidity and Capital Resources Overview" above, we currently have an $850 million revolving credit facility. Borrowings under the credit facility will bear interest, at our option, at either (a) a base rate, which will be a rate equal to the greatest of (i) the prime rate, (ii) the U.S. federal funds rate plus 0.5% and (iii) a one-month reserve adjusted Eurodollar rate plus 1.00% or (b) a reserve adjusted Eurodollar Rate, plus, in each case, an applicable margin. For loans bearing interest based on the base rate, the applicable margin was initially 1.00%, and for loans bearing interest based on the reserve adjusted Eurodollar rate, the applicable margin was initially 2.00%. After June 25, 2014, the applicable margin ranges from 0.75% to 2.75%, based upon our total leverage ratio and whether we have elected the base rate or the reserve adjusted Eurodollar rate. We do not currently hedge the interest rate risk on our borrowings under the credit facility. However, in the future we may consider hedging the interest rate risk or may consider choosing longer Eurodollar borrowing terms in order to fix all or a portion of our borrowings for a period of time. We estimate that a 1% increase in interest rates would decrease the fair value of the debt by $0.1 million based on the debt obligations as of September 30, 2014.

Credit Risk

We are exposed to credit risk. Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. We manage our exposure to credit risk associated with customers to whom we extend credit through a credit approval process which includes credit analysis, the establishment of credit limits and ongoing monitoring procedures. We may request letters of credit, cash collateral, prepayments or guarantees as forms of credit support. We have historically experienced only minimal credit losses in connection with our receivables.

A substantial majority of our revenue is produced under long-term, fee-based contracts with high-quality customers. The customer base we currently serve under these contracts generally has a strong credit profile, with the majority of our revenues derived from customers with investment grade credit ratings as of September 30, 2014.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our principal executive officer and principal financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rule 13a- 15(e) or Rule 15d- 15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this report, and has concluded that our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported, within the time periods specified in the Securities and Exchange Commission's rules and forms including, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosures.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the quarter ended September 30, 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Assessment of Internal Control over Financial Reporting

The SEC, as required by Section 404 of the Sarbanes-Oxley Act, adopted rules requiring every public company that files reports with the SEC to include a management report on such company's internal control over financial reporting in its annual report. Pursuant to the recently enacted Jumpstart Our Business Startups Act of 2012 (the "JOBS Act"), our independent registered public accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002 for up to five years or through such earlier date that we are no longer an "emerging growth company" as defined in the JOBS Act. Accordingly, our first Annual Report on Form 10-K did not include a report of management's assessment regarding internal control over financial reporting or an attestation report of our independent registered public accounting firm due to a transition period established by SEC rules applicable to newly public companies. Our management will be required to provide an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2014 and, accordingly, a testing program is being executed.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

See Note 16 – Legal and Environmental Matters to the consolidated financial statements included in Part 1—Item 1.—Financial Statements of this Quarterly Report, which is incorporated here by reference.

Item 1A. Risk Factors

Item 1A of our 2013 Form 10-K for the year ended December 31, 2013 sets forth information relating to important risks and uncertainties that could materially adversely affect our business, financial condition or operating results. Those risk factors continue to be relevant to an understanding of our business, financial condition and operating results for the quarter ended September 30, 2014. Other than as set forth below, there have been no material changes to the risk factors contained in our 2013 Form 10-K for the year ended December 31, 2013.

Limited partner interests are inherently different from shares of capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. If any of the following risks were to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, we might not be able to pay the minimum quarterly distribution on our common units, or pay any distribution at all, and the trading price of our common units could decline.

Risks Related to Our Business

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner and its affiliates, to enable us to pay the quarterly distribution at the current distribution level, or at all, to holders of our common and subordinated units.

In order to pay the minimum quarterly distribution of $0.2875 per unit, or $1.15 per unit on an annualized basis, we will require available cash of approximately $14.3 million per quarter, or $57.3 million per year, based on the number of common, subordinated and general partner units currently outstanding. We may not have sufficient available cash from operating surplus each quarter to enable us to pay the quarterly distribution at the current distribution level, at the minimum quarterly distribution level, or at all. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the level of firm transportation and storage capacity sold, the volume of natural gas and crude oil we transport and the volume of natural gas we store and process;
- the level of production of crude oil and natural gas and the resultant market prices of natural gas, NGLs and crude oil; regional, domestic and foreign supply and perceptions of supply of natural gas and crude oil; the level of demand and perceptions of demand in our end-user markets; and actual and anticipated future prices of natural gas, crude oil and other commodities (and the volatility thereof), which may impact our ability to renew and replace firm transportation, storage and processing agreements;
- regulatory action affecting the supply of, or demand for, natural gas and crude oil, the rates we can charge on our assets, how we contract for services, our existing contracts, our operating costs or our operating flexibility;
- changes in the fees we charge for our services;
- the effect of seasonal variations in temperature on the amount of natural gas and crude oil that we transport and the amount of natural gas that we store, process and treat;
- the relationship between natural gas and NGL prices and resulting effect on processing margins;
- the realized pricing impacts on revenues and expenses that are directly related to commodity prices;
- the level of competition from other midstream energy companies in our geographic markets;
- the creditworthiness of our customers;
- the level of our operating and maintenance costs;
- damages to pipelines, facilities, related equipment and surrounding properties caused by earthquakes, floods, fires, severe weather, explosions and other natural disasters or acts of terrorism;
- outages at our processing facilities;

- leaks or accidental releases of hazardous materials into the environment, whether as a result of human error or otherwise; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, including:

- the level and timing of capital expenditures we make;
- the level of our general and administrative expenses, including reimbursements to our general partner and its affiliates, including TD, for services provided to us;
- the cost of acquisitions, if any;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our debt agreements;
- the amount of cash reserves established by our general partner; and
- other business risks affecting our cash levels.

If we are not able to renew or replace expiring customer contracts at favorable rates or on a long-term basis, our financial condition, results of operation, cash flows and ability to make cash distributions to our unitholders will be adversely affected. With respect to our natural gas transportation and logistics segment, we have experienced decreases in revenues as compared to historical periods resulting from decreased renewals of long-haul firm capacity contracts with off-system customers over the last few years. If this trend continues, our ability to make cash distributions to our unitholders may be materially impacted.

We transport, store and process a substantial majority of the natural gas on our systems under long-term contracts with terms of various durations. For the year ended December 31, 2013, approximately 93% of our transportation and storage revenues were generated under firm transportation and storage contracts. Our natural gas firm transportation and storage contracts have a weighted average maturity of approximately four years and two years, respectively as of December 31, 2013. As of December 31, 2013, the weighted average duration of our processing contracts was approximately four years. As these contracts expire, we may be unable to obtain new contracts on terms similar to those of our existing contracts, or at all. If we are unable to promptly resell capacity from expiring contracts on equivalent terms, our revenues may decrease and our ability to make cash distributions to our unitholders may be materially impaired.

For example, over the past several years, a number of our natural gas transportation and storage customers have opted not to renew their contracts for service on the TIGT System. We believe those non-renewals have been caused both by increased competition from large diameter long-haul pipeline systems that are more efficient and cost effective at transporting natural gas over long distances, as well as reduced drilling activity for dry gas in the Rocky Mountain region. These former customers are generally large producers that primarily used the TIGT System to access interstate pipelines for ultimate delivery to consuming markets outside our areas of operations, as opposed to our current customer base, which is primarily comprised of on-system regional customers, such as LDCs. The non-renewal of these transportation contracts has resulted in decreases in firm contracted capacity on the TIGT System and related decreases in total revenue. For example, our average firm contracted capacity decreased from 842 MMcf/d for the year ended December 31, 2010 to 679 MMcf/d for the year ended December 31, 2013 and transportation services revenue decreased from $142.4 million to $98.6 million over the same period, primarily due to the loss of revenue from the non- renewal of transportation contracts.

We also may be unable to maintain the long-term nature and economic structure of our current contract portfolio over time. Depending on prevailing market conditions at the time of a contract renewal, transportation, storage and processing customers with fee-based contracts may desire to enter into contracts under different fee arrangements, and our potential customers may be generally unwilling to enter into long-term contracts. To the extent we are unable to renew or replace our existing contracts on terms that are favorable to us or successfully manage the long-term nature and economic structure of our contract mix over time, our revenues and cash flows could decline and our ability to make distributions to our unitholders could be materially and adversely affected. In addition, if an existing customer terminates or breaches its long-term firm transportation, storage or processing contract, we may be subject to a loss of revenue if we are unable to promptly resell the capacity to another customer on substantially equivalent terms.

Our ability to renew or replace our expiring contracts on terms similar to, or more attractive than, those of our existing contracts is uncertain and depends on a number of factors beyond our control, including:

- the level of existing and new competition to provide transportation, storage and processing services to our markets;
- the macroeconomic factors affecting crude oil and natural gas gathering economics for our current and potential customers;
- the balance of supply and demand for natural gas and crude oil, on a short-term, seasonal and long-term basis, in the markets we serve;
- the extent to which the customers in our markets are willing to contract on a long-term basis; and
- the effects of federal, state or local laws or regulations on the contracting practices of our customers.

Increased competition from other companies that provide natural gas transportation, storage and processing and crude oil transportation services, or from alternative fuel sources, could have a negative impact on the demand for our services, which could materially and adversely affect our financial results.

Our ability to renew or replace our existing contracts at rates sufficient to maintain current revenues and current cash flows could be adversely affected by the activities of our competitors. Some of our competitors have greater financial, managerial and other resources than we do and control substantially more transportation, storage and processing capacity and/or crude oil transportation capacity than we do. In addition, some of our competitors have assets in closer proximity to natural gas and/or crude oil supplies and have available idle capacity in existing assets that would not require new capital investments for use. For example, several pipelines access many of the same basins as our natural gas pipeline systems and transport gas to customers in the Rocky Mountain and Midwest regions of the United States. In addition, numerous other crude oil pipeline projects have been announced recently that would compete directly with our Pony Express crude oil pipeline system. Our competitors may expand or construct new transportation, storage or processing systems that would create additional competition for the services we provide to our customers, or our customers may develop their own transportation, storage and processing facilities in lieu of using ours. The potential for the construction of new processing facilities in our areas of operation is particularly acute due to the nature of the processing industry and the attractive drilling profile of geographic areas served by our Midstream Facilities. Furthermore, TD and its affiliates are not limited in their ability to compete with us.

If our competitors were to substantially decrease the prices at which they offer their services, we may be unable to compete effectively and our cash flows and ability to make distributions to our unitholders may be materially impaired.

Further, natural gas as a fuel, and fuels derived from crude oil, compete with other forms of energy available to users, including electricity, coal and other liquid fuels. Increased demand for such forms of energy at the expense of natural gas or fuels derived from crude oil could lead to a reduction in demand for our services.

All of these competitive pressures could make it more difficult for us to renew our existing long-term, firm transportation, storage and processing contracts when they expire or to attract new customers as we seek to expand our business, which could have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, competition could intensify the negative impact of factors that decrease demand for natural gas and crude oil in the markets we serve, such as adverse economic conditions, weather, higher fuel costs and taxes or other governmental or regulatory actions that directly or indirectly increase the cost or limit the use of natural gas or crude oil.

If we are unable to make acquisitions on economically acceptable terms from Tallgrass Development or third parties, our future growth will be limited, and the acquisitions we do make may reduce, rather than increase, our cash generated from operations on a per unit basis.

Our ability to grow depends, in part, on our ability to make acquisitions that increase our cash generated from operations on a per unit basis. The acquisition component of our strategy is based, in large part, on our expectation of ongoing divestitures of midstream energy assets by industry participants, including Tallgrass Development. Other than Tallgrass Development's obligation to offer us certain assets (if Tallgrass Development decides to sell such assets) pursuant to the right of first offer under the Omnibus Agreement, we have no contractual arrangement with Tallgrass Development that would require it to provide us with an opportunity to acquire midstream assets that it may sell. Accordingly, while we believe Tallgrass Development will be incentivized pursuant to its economic relationship with us to offer us opportunities to purchase midstream assets, there can be no assurance that any such offer will be made, and there can be no assurance we will reach agreement on the terms with respect to any acquisition opportunities offered to us by Tallgrass Development. Furthermore, many factors could impair our access to future midstream assets, including a change in control of Tallgrass Development or a transfer of the IDRs by our general partner to a third party. A material decrease in divestitures of midstream energy assets from Tallgrass Development or otherwise would limit our opportunities for future acquisitions and could have a material adverse effect on our business, results of operations, financial condition and ability to make quarterly cash distributions to our unitholders.

Our future growth and ability to increase distributions will be limited if we are unable to make accretive acquisitions from Tallgrass Development or third parties because, among other reasons, (i) Tallgrass Development elects not to sell or contribute additional assets to us or to offer acquisition opportunities to us, (ii) we are unable to identify attractive third-party acquisition opportunities, (iii) we are unable to negotiate acceptable purchase contracts with Tallgrass Development or third parties, (iv) we are unable to obtain financing for these acquisitions on economically acceptable terms, (v) we are outbid by competitors or (vi) we are unable to obtain necessary governmental or third-party consents. Furthermore, even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations on a per unit basis.

Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about volumes, revenue and costs, including synergies and potential growth;
- an inability to maintain or secure adequate customer commitments to use the acquired systems or facilities;
- an inability to integrate successfully the assets or businesses we acquire;
- the assumption of unknown liabilities for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management's and employees' attention from other business concerns;
- unforeseen difficulties operating in new geographic areas or business lines; and
- a decrease in liquidity and increased leverage as a result of using significant amounts of available cash or debt to finance an acquisition.

If any acquisition eventually proves not to be accretive to our distributable cash flow per unit, it could have a material adverse effect on our business, results of operations, financial condition and ability to make quarterly cash distributions to our unitholders.

If we are unable to obtain needed capital or financing on satisfactory terms to fund expansions of our asset base, our ability to make quarterly cash distributions may be diminished or our financial leverage could increase.

In order to expand our asset base through acquisitions or capital projects, we may need to make expansion capital expenditures. If we do not make sufficient or effective expansion capital expenditures, we will be unable to expand our business operations and may be unable to maintain or raise the level of our quarterly cash distributions. We could be required to use cash from our operations or incur borrowings or sell additional common units or other limited partner interests in order to fund our expansion capital expenditures. Using cash from operations will reduce cash available for distribution to our common unitholders. Our ability to obtain bank financing or to access the capital markets for future equity or debt offerings may be limited by our financial condition at the time of any such financing or offering as well as the covenants in our debt agreements, general economic conditions and contingencies and uncertainties that are beyond our control. Even if we are successful in obtaining funds for expansion capital expenditures through equity or debt financings, the terms thereof could limit our ability to pay distributions to our common unitholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional limited partner interests may result in significant common unitholder dilution and increase the aggregate amount of cash required to maintain the then-current distribution rate, which could materially decrease our ability to pay distributions at the then-current distribution rate.

We do not currently have any commitment with our general partner or other affiliates, including Tallgrass Development, to provide any direct or indirect financial assistance to us.

We are exposed to direct commodity price risk with respect to some of our processing revenues, and our exposure to direct commodity price risk may increase in the future.

Our processing segment operates under two types of contractual arrangements that expose our cash flows to increases and decreases in the price of natural gas and NGLs: percent of proceeds and keep whole arrangements. As of December 31, 2013, approximately 34% of the reserved capacity in our processing segment was contracted under percent of proceeds or keep whole arrangements. Under percent of proceeds arrangements, we generally purchase natural gas from producers and retain from the sale an agreed percentage of pipeline-quality gas and NGLs resulting from our processing activities at market prices. These arrangements provide upside in high commodity price environments, but result in lower margins in low commodity price environments. Under keep whole arrangements, we are required to replace the Btu content of NGLs extracted from the inlet wet gas processed with purchased dry natural gas, some of which we must purchase at market prices. Under these types of arrangements our revenues and our cash flows increase or decrease as the prices of natural gas and NGLs fluctuate. The relationship between natural gas prices and NGL prices may also affect our profitability. When natural gas prices are low relative to NGL prices, it is more profitable for us to process natural gas under keep whole arrangements. When natural gas prices are high relative to NGL prices, it is less profitable for us and our customers to process natural gas both because of the higher value of natural gas and the increased cost (principally that of natural gas as a feedstock and a fuel) of separating the mixed NGLs from the natural gas. As a result, we may experience periods in which higher natural gas prices relative to NGL prices reduce our processing margins or reduce the volume of natural gas processed at some of our plants. In addition, NGL prices have historically been correlated to the market price of oil and as a result any significant changes in oil prices could also indirectly impact our operations. NGL and natural gas prices are volatile and are impacted by changes in the supply and demand for NGLs and natural gas, as well as market uncertainty. We do not currently hedge the commodity exposure in our processing contracts and, as a result, our revenues, financial condition and results of operations could be adversely impacted by fluctuations in the prices of natural gas and NGLs. As a result of our commodity price exposure, significant prolonged changes in natural gas and NGL prices could have a material adverse effect on our financial condition, results of operations and our ability to make cash distributions to our unitholders.

If third-party pipelines or other midstream facilities interconnected to our systems become partially or fully unavailable, or if the volumes we transport do not meet the quality requirements of such pipelines or facilities, our revenues and our ability to make distributions to our unitholders could be adversely affected.

Our natural gas transportation, storage and processing facilities and our oil transportation facilities connect to other pipelines or facilities owned and operated by unaffiliated third parties, such as Phillips 66 Company, Deeprock Development, LLC and others. For example, a substantial majority of the NGLs we process are transported on the Powder River pipeline owned by Phillips 66 Company, and therefore, any downtime on this pipeline as a result of maintenance or force majeure would adversely affect us. In addition, our Pony Express crude oil pipeline depends on two upstream joint tariff pipelines, Belle Fourche and Hiland, for a substantial portion of the crude oil delivered into the Pony Express system. Plus, nearly all of the crude oil we transport on the Pony Express pipeline is stored in crude oil tanks located on or pumped over to downstream pipelines that interconnect through the Deeprock Development terminal facility in Cushing, Oklahoma. The continuing operation of such third- party pipelines, processing plants, crude oil terminal facilities and other midstream facilities is not within our control. These pipelines, plants and other midstream facilities may become unavailable because of testing, turnarounds, line repair, reduced operating pressure, lack of operating capacity, regulatory requirements, curtailments of receipt or deliveries due to insufficient capacity or because of damage from weather events or other operational hazards. In addition, if the costs to us to access and transport on these third- party pipelines significantly increase, our profitability could be reduced. If any such increase in costs occurred, if any of these pipelines or other midstream facilities become unable to receive, transport or process natural gas or to store or transport crude oil, or if the volumes we transport or process do not meet the quality requirements of such pipelines or facilities, our revenues and our ability to make quarterly cash distributions to our unitholders could be adversely affected. For example, in May 2014 Phillips 66 notified us of an allegation that Tallgrass Midstream, LLC had been delivering NGLs to the Powder River NGL pipeline with methanol levels in excess of applicable tolerances. Subsequent third party lab analysis of an April 2014 composite sample from the Douglas Gas Plant confirmed that recent injections may have had excessive levels of methanol. The Douglas plant was shut in completely for five days, and operated at approximately 50% of its processing capacity for another 10 days, as a result. Tallgrass Midstream has incurred off-spec fees from Phillips 66 of approximately $1.4 million during the nine months ended September 30, 2014. Tallgrass is working with suppliers to reduce methanol levels, but off-spec fees may continue over the next several months. Phillips 66 may also, among other things, seek payment for any other costs (including those associated with overtime, testing, and shipping), penalties or damages allegedly incurred by them in connection with their processing, use or sale of the NGLs. We have sought, and will continue to seek, recovery from our upstream suppliers that we believe have delivered off-spec product to our processing facilities, although the amount of costs and penalties we can recover from upstream suppliers is uncertain. If we are required to make additional substantial payments to Phillips 66 for costs, penalties or other damages and are unable to recover such amounts from upstream suppliers, our revenues and ability to make distributions to unitholders could be adversely affected.

As a result of the acquisition of an interest in the Pony Express Pipeline, we are engaged in crude oil transportation, which is a new line of business for us. We cannot provide assurance that our expansion into this line of business will succeed.

In September 2014, we acquired a 33.3% membership interest in the Pony Express Pipeline, which consists of an approximately 690 mile crude oil pipeline commencing in Guernsey, Wyoming and terminating in Cushing, Oklahoma, with delivery points at Ponca City Refinery and Deeprock Development in Cushing. In addition, upon completion of ongoing construction, the Pony Express crude oil pipeline system will also include an approximately 66 mile lateral in northeast Colorado that will commence in Weld County, Colorado and interconnect with the Pony Express mainline just east of Sterling, Colorado. The ownership and operation of a crude oil pipeline is a new line of business for us, as our operations were previously focused on the transportation, storage and processing of natural gas. Operating a crude oil pipeline system requires different operating strategies and different managerial expertise than our current operations, and a crude oil pipeline system is subject to additional or different regulations. Failure to timely and successfully develop this new line of business in conjunction with our existing operations may have a material adverse effect on our business, financial condition and results of operations.

Our natural gas and crude oil operations are subject to extensive regulation by federal, state and local regulatory authorities. Changes or additional regulatory measures adopted by such authorities could have a material adverse effect on our business, financial condition, and results of operations.
Our natural gas transportation and storage operations are regulated by the FERC, under the Natural Gas Act of 1938, or the NGA, the Natural Gas Policy Act of 1978, or the NGPA, and the Energy Policy Act of 2005, or EP Act 2005. The TIGT System and Trailblazer pipeline each operates under a tariff approved by the FERC that establishes rates, cost recovery mechanisms and terms and conditions of service to our customers. The rates and terms of service on the Pony Express Pipeline are subject to regulation by the FERC under the Interstate Commerce Act, or the ICA, and the Energy Policy Act of 1992. We provide interstate transportation service on the Pony Express Pipeline pursuant to tariffs on file with the FERC.
Generally, the FERC's authority over natural gas facilities extends to:

- rates, operating terms and conditions of service;
- the form of tariffs governing service;
- the types of services we may offer to our customers;
- the certification and construction of new, or the expansion of existing, facilities;
- the acquisition, extension, disposition or abandonment of facilities;
- creditworthiness and credit support requirements;
- the maintenance of accounts and records;
- relationships among affiliated companies involved in certain aspects of the natural gas business;
- depreciation and amortization policies; and
- the initiation and discontinuation of services.

The FERC's authority over crude oil pipelines is less broad, extending to:

- rates, operating terms and conditions of service;
- the form of tariffs governing service;
- the maintenance of accounts and records;
- relationships among affiliated transporters and shippers; and
- depreciation and amortization policies.

Interstate natural gas pipelines subject to the jurisdiction of the FERC may not charge rates or impose terms and conditions of service that, upon review by the FERC, are found to be unjust, unreasonable, unduly discriminatory, or preferential. The maximum recourse rate that we may charge for our natural gas transportation and storage services is established through the FERC's ratemaking process. The maximum applicable recourse rate and terms and conditions for service are set forth in our FERC-approved tariff.
Pursuant to the NGA, existing interstate natural gas transportation and storage rates and terms and conditions of service may be challenged by complaint and are subject to prospective change by the FERC. Additionally, rate increases and changes to terms and conditions of service proposed by a regulated interstate pipeline may be protested and such increases or changes can be delayed and may ultimately be rejected by the FERC. We currently hold authority from the FERC to charge and collect (i) "recourse rates" (i.e., the maximum cost-based rates an interstate natural gas pipeline may charge for its services under its tariff); (ii) "discount rates" (i.e., rates offered by the natural gas pipeline to shippers at discounts vis-à-vis the recourse rates and fall within the cost-based maximum and minimum rate levels set forth in the natural gas pipeline's tariff); and (iii) "negotiated rates" (i.e., rates negotiated and agreed to by the pipeline and the shipper for the contract term that may fall within or outside of the cost-based maximum and minimum rate levels set forth in the tariff, and which are individually filed with the FERC for review and acceptance). When capacity is available and offered for sale, the rates (which include reservation, commodity, surcharges, fuel and gas lost and unaccounted for) at which such capacity is sold are subject to regulatory approval and oversight. Regulators and customers on our natural gas pipeline systems have the right to protest or otherwise challenge the rates that we charge under a process prescribed by applicable regulations. The FERC may also initiate reviews of our rates. Customers on our natural gas pipeline systems may also dispute terms and conditions contained in our agreements, as well as the interpretation and application of our tariffs, among other things.

Rates for crude oil transportation service must be filed as a tariff with the FERC and are subject to applicable FERC regulation. The filed tariff rates include contract rates entered into with shippers willing to make long term commitments to the pipeline to support new pipeline capacity and “walk-up” rates available to uncommitted non-contract shippers. Crude oil pipelines typically must reserve at least ten percent of their capacity for walk-up shippers. Crude oil pipeline tariff rates may be adjusted, positively or negatively, on an annual basis through a FERC indexing procedure. A crude oil pipeline may also file new tariff rates at any time, subject to shipper contract restrictions and FERC regulatory procedures. The filing of any indexed rate increase or other rate increase may be protested and subjected to cost-of-service review by the FERC to determine whether the proposed new rate is just and reasonable.

Under the ICA, which applies to FERC-regulated liquids pipelines such as the Pony Express crude oil pipeline system, parties having standing may challenge newly filed tariff rates and terms and conditions of service by filing a protest within the time specified by the FERC. The FERC is authorized to suspend, subject to refund, the effectiveness of a protested rate for up to seven months while it determines if the protested rate is just and reasonable. If a protested rate is found to be unjust and unreasonable, FERC may order refunds. The ICA also allows parties having standing to file complaints in regard to existing tariff rates and provisions. If the complaint is not resolved, the FERC may conduct a hearing and order the crude oil pipeline to make reparations going back for up to two years prior to the date on which a complaint was filed if a rate is found to be unjust and unreasonable. We cannot guarantee that any new or existing rate on our Pony Express crude oil pipeline system would not be rejected or modified by the FERC, or subjected to refunds or reparations. While the FERC regulates rates and terms and conditions of service for transportation of crude oil in interstate commerce by pipeline, state agencies may also regulate facilities (including construction, acquisition, disposition, financing, and abandonment), rates, and terms and conditions of service for crude oil pipeline transportation in intrastate commerce. Any successful challenge by a regulator or shipper in any of these matters could have a material adverse effect on our business, financial condition and results of operations.

Trailblazer, one of our interstate natural gas pipelines, has two feed stocks to power its compressors: (1) natural gas and (2) electric power. For the natural gas compression, customers are charged a gas retainage percentage. For the electric compression, customers are charged a commodity rate for the electricity used at the pipeline’s stations. The volume of gas and cost of electric power are tracked and adjusted in annual periodic rate adjustment filings made pursuant to the tariff. Lost and unaccounted for gas is also tracked and adjusted in annual periodic rate adjustment filings. These costs were subject to the NGA Section 4 rate case initiated by the Trailblazer pipeline and resolved by settlement as approved by the FERC in May 2014. On TIGT, our gas compressor fuel costs and the cost of lost and unaccounted for gas, together referred to as Fuel Retention Factors, are recovered by retaining a fixed percentage of natural gas throughput on our transportation and storage facilities. These Fuel Retention Factors were the subject of a Section 5 proceeding initiated by the FERC that we resolved with customers by a settlement approved by the FERC in September 2011.

The FERC’s jurisdiction over natural gas facilities extends to the certification and construction of interstate transportation and storage facilities, including, but not limited to, acquisitions, facility maintenance, expansions, and abandonment of facilities and services. With some exceptions applicable to smaller projects, auxiliary facilities, and certain facility replacements, prior to commencing construction of new or existing interstate natural gas transportation and storage facilities, an interstate pipeline must obtain a certificate authorizing the construction from, or file to amend its existing certificate with, the FERC. Typically, a significant expansion project requires review by a number of governmental agencies, including state and local agencies, whose cooperation is important in completing the regulatory process on schedule. Any delay or refusal by an agency to issue authorizations or permits as requested for one or more of these projects may mean that they will be constructed in a manner or with capital requirements that we did not anticipate or that we will not be able to pursue these projects. Such delay, modification or refusal could materially and negatively impact the additional revenues expected from these projects. The FERC does not regulate the construction, expansion, or abandonment of crude oil pipelines nor the initiation or discontinuation of services on those pipelines, provided that the action taken is not discriminatory or preferential among similarly situated shippers.

FERC conducts audits to verify that the websites of interstate natural gas pipelines accurately provide information on the operations and availability of services on the pipeline. FERC regulations also require entities providing natural gas and crude oil transportation services to comply with uniform terms and conditions for service, as set forth in publicly available tariffs or, as it concerns natural gas facilities, agreements for transportation and storage services executed between interstate pipelines and their customers. These service agreements are generally required to conform, in all material respects, with the standard form of service agreements set forth in the natural gas pipeline's FERC-approved tariff. The pipeline and a customer may choose to enter into a non-conforming service agreement so long as this agreement is filed with, and accepted by, the FERC. In the event that the FERC finds that an agreement, in whole or part, is materially non-conforming, FERC could reject the agreement or require us to modify the agreement, or alternatively require us to modify our tariff so that the non-conforming provisions are generally available to all customers. Agreements entered into with crude oil shippers are generally not available for public review, but the rates and terms and service provided to similarly situated shippers may not be unduly discriminatory or preferential.

The FERC has promulgated rules and policies covering many aspects of our natural gas pipeline business, including regulations that require us to provide firm and interruptible transportation service on an open access basis that is not unduly discriminatory or preferential, provide internet access to current information about our available pipeline capacity and other relevant transmission information, and permit pipeline shippers to release contracted transportation and storage capacity to other shippers, thereby creating secondary markets for such services. FERC regulations also prevent interstate natural gas pipelines from sharing customer information with marketing affiliates, and restrict how interstate natural gas pipelines share transportation with marketing affiliates. FERC regulations require that interstate natural gas pipelines function independently of their marketing affiliates. Crude oil pipelines subject to the ICA must comply with similar FERC regulations that require the pipeline to act as a common carrier and not engage in undue discrimination or preferential treatment with respect to shippers..

FERC policies also govern how interstate natural gas pipelines respond to interconnection requests from third party facilities, including other pipelines. Generally, an interstate natural gas pipeline must grant an interconnection request upon the satisfaction of several conditions. As a consequence, an interstate natural gas pipeline faces the risk that an interconnecting third party pipeline may pose a risk of additional competition to serve a particular market.

Failure to comply with applicable provisions of the NGA, NGPA, EPAct and certain other laws, as well as with the regulations, rules, orders, restrictions and conditions associated with these laws, could result in the imposition of administrative and criminal remedies, including without limitation, revocation of certain authorities, disgorgement of ill-gotten gains, and civil penalties of up to $1.0 million per day, per violation. Violations of the ICA, the Energy Policy Act of 1992, or regulations and orders promulgated by the FERC are also subject to administrative and criminal penalties and remedies, including forfeiture and individual liability.

In addition, new laws or regulations or different interpretations of existing laws or regulations applicable to our pipeline system or midstream facilities could have a material adverse effect on our business, financial condition, results of operations and prospects. For example, the FERC may not continue to pursue its approach of pro-competitive policies as it considers matters such as interstate pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity and transportation and storage facilities. We may face challenges to our rates or terms of service in the future. Any successful challenge could materially adversely affect our future earnings and cash flows.

The rates of our regulated assets are subject to review and possible adjustment by federal and state regulators, which could adversely affect our business, results of operations, financial condition and ability to make quarterly cash distributions to our unitholders.

Our shippers, the FERC, or other interested stakeholders, such as state regulatory agencies, may challenge the rates or the terms and conditions of service applicable to our natural gas or crude oil pipeline tariffs, unless they have entered into agreements not to challenge such tariffs. Our crude oil firm contract shippers have generally agreed not to complain or protest rates unless they are in conflict with their contracts. Also, an uncontested settlement approved by the FERC in May 2014 on Trailblazer provided that neither Trailblazer nor any customer or participant that is defined therein as a “Settling Party,” may file prior to January 1, 2016 to modify the rates set forth in the settlement or to modify certain terms and conditions of the tariff regarding, inter alia, the periodic rate adjustment filings on fuel, lost and unaccounted for gas, the power cost tracker, and revenue crediting regarding short-term interruptible and firm transportation agreements. Further, the rates on our TIGT natural gas pipeline system were subject to a NGA Section 5 proceeding initiated by our shippers relating to TIGT's fuel retention factors, which generally are recovered by retaining a fixed percentage of natural gas throughput on our natural gas transportation and storage facilities. TIGT resolved these issues with customers by a settlement approved by the FERC in September 2011, which resulted in a 27% reduction in the Fuel Retention Factors billed to shippers effective June 1, 2011, causing a decrease in transportation and storage revenue. The Section 5 Settlement also provided for a second stepped reduction, resulting in a total 30% reduction in the Fuel Retention Factors billed to shippers and effective January 1, 2012, for certain segments of the former Pony Express natural gas pipeline system.

On our crude oil pipeline system, shippers may challenge new or existing rates at any time. As a result of settlement or by order of FERC following hearing, our rates may be reduced. If a shipper files a complaint, and if the complaint is not resolved with that shipper, to the extent the FERC determines after hearing that we have collected payment on rates not previously found to be just and reasonable, we may be required to pay reparations to that shipper for up to two years prior to the date on which a complaint was filed. Regardless of the prospective just and reasonable rate, reparations may not be required below the last rates determined by FERC to be just and reasonable. In other words, crude oil pipelines are not required to make reparations that refund revenues collected pursuant to rates previously

determined to be just and reasonable.
Successful challenges to rates charged on our natural gas and crude oil pipeline systems could have a material adverse effect on our business, results of operations, financial condition and ability to make quarterly cash distributions to our unitholders.
We are exposed to the creditworthiness and performance of our customers, suppliers and contract counterparties, and any material nonpayment or nonperformance by one or more of these parties could adversely affect our financial and operating results.
Although we attempt to assess the creditworthiness of our customers, suppliers and contract counterparties, there can be no assurance that our assessments will be accurate or that there will not be a rapid or unanticipated deterioration in their creditworthiness, which may have an adverse impact on our business, results of operations, financial condition and ability to make cash distributions to our unitholders. In addition, our long-term firm transportation and storage contracts obligate our

customers to pay demand charges regardless of whether they transport or store natural gas or crude oil on our facilities, except for certain circumstances when we are unable to schedule the customer's nomination for service . As a result, during the term of our long-term firm transportation and storage contracts and absent an event of force majeure, our revenues will generally depend on our customers' financial condition and their ability to pay rather than upon the amount of natural gas or crude oil transported. Further, our contract counterparties may not perform or adhere to our existing or future contractual arrangements. Any material nonpayment or nonperformance by our contract counterparties due to inability or unwillingness to perform or adhere to contractual arrangements could have an adverse impact on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

The procedures and policies we use to manage our exposure to credit risk, such as credit analysis, credit monitoring and, in some cases, requiring credit support, cannot fully eliminate counterparty credit risks. To the extent our procedures and policies prove to be inadequate, our financial and operational results may be negatively impacted. Some of our counterparties may be highly leveraged or have limited financial resources and will be subject to their own operating and regulatory risks. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with such parties. In addition, volatility in commodity prices might have an impact on many of our counterparties, which, in turn, could have a negative impact on their ability to meet their obligations to us and may also increase the magnitude of these obligations.

Any material nonpayment or nonperformance by our counterparties could require us to pursue substitute counterparties for the affected operations, reduce operations or provide alternative services. There can be no assurance that any such efforts would be successful or would provide similar financial and operational results.

Any significant decrease in available supplies of natural gas or crude oil in our areas of operation, or redirection of existing natural gas or crude oil supplies to other markets, could adversely affect our business and operating results.

Our business is dependent on the continued availability of natural gas and crude oil production and reserves. Production from existing wells and natural gas and crude oil supply basins with access to our transportation, storage and processing facilities will naturally decline over time. The amount of natural gas and crude oil reserves underlying these wells may also be less than anticipated, and the rate at which production from these reserves declines may be greater than anticipated. Accordingly, to maintain or increase the contracted capacity or the volume of natural gas and crude oil transported and natural gas stored and processed on our systems and cash flows associated therewith, our customers must continually obtain adequate supplies of natural gas and crude oil.

However, the development of additional natural gas and crude oil reserves requires significant capital expenditures by others for exploration and development drilling and the installation of production, storage, transportation and other facilities that permit natural gas and crude oil to be produced and delivered to our transportation, storage and processing facilities. In addition, low prices for natural gas and crude oil, regulatory limitations, including environmental regulations, or the lack of available capital for these projects could have a material adverse effect on the development and production of additional reserves, as well as storage, pipeline transportation, and import and export of natural gas and crude oil supplies. In addition, production may fluctuate for other reasons, including, for example, in the case of crude oil, the inability of the members of the Organization of the Petroleum Exporting Countries, or OPEC, to agree to and maintain production controls. Furthermore, competition for natural gas and crude oil supplies to serve other markets could reduce the amount of natural gas and crude oil supply available for our customers. Accordingly, to maintain or increase the contracted capacity or the volume of natural gas and crude oil transported on our systems and cash flows associated with our operations, our customers must compete with others to obtain adequate supplies of natural gas and crude oil.

If new supplies of natural gas and crude oil are not obtained to replace the natural decline in volumes from existing supply basins, if natural gas and crude oil supplies are diverted to serve other markets, if environmental regulators restrict new natural gas and crude oil drilling or if OPEC fails to agree to and maintain production controls, the overall demand for transportation, storage and processing services on our systems would decline, which could have a material adverse effect on our ability to renew or replace our current customer contracts when they expire and on our business, financial condition, results of operations and ability to make quarterly cash distributions to our unitholders.

Constructing new assets subjects us to risks of project delays, cost overruns and lower-than-anticipated volumes of natural gas or crude oil once a project is completed. Our operating cash flows from our capital projects may not be immediate or meet our expectations.

One of the ways we may grow our business is by constructing additions or modifications to our existing facilities. We also may construct new facilities, either near our existing operations or in new areas. For example, in 2013 we completed an expansion of our Casper and Douglas plants to increase processing capacity and upgrade compression. In addition, in 2014, Pony Express substantially completed its approximately 690-mile crude oil pipeline commencing in Guernsey, Wyoming and terminating in Cushing, Oklahoma and is currently constructing an approximately 66 mile lateral in Northeast Colorado.

Construction projects require significant amounts of capital and involve numerous regulatory, environmental, political, legal and operational uncertainties, many of which are beyond our control. These projects also involve numerous economic uncertainties, including the impact of inflation on project costs and the availability of required resources.
We may be unable to complete announced construction projects, including the potential expansion of the Pony Express pipeline system announced in our public filings, on schedule, at the budgeted cost, or at all, which could have a material adverse effect on our business and results of operations. Moreover, we may not receive any material increase in operating cash flow from a project for some time. For instance, if we expand a pipeline or processing facility, the construction expenditures may occur over an extended period of time, yet we will not receive any material increases in cash flow until the project is completed and fully operational. In addition, our cash flow from a project may be delayed or may not meet our expectations. Our project specifications and expectations regarding project cost, timing, asset performance, investment returns and other matters usually rely in part on the expertise of third parties such as engineers, technical experts and construction contractors. These estimates may prove to be inaccurate because of numerous operational, technological, economic and other uncertainties.
We rely in part on estimates from producers regarding the timing and volume of anticipated natural gas and crude oil production. Production estimates are subject to numerous uncertainties, all of which are beyond our control. These estimates may prove to be inaccurate, and new facilities may not attract sufficient volumes to achieve our expected cash flow and investment return.
Our success depends on the supply and demand for natural gas and crude oil.
The success of our business is in many ways impacted by the supply and demand for natural gas and crude oil. For example, our business can be negatively impacted by sustained downturns in supply and demand for natural gas and crude oil in the markets that we serve, including reductions in our ability to renew contracts on favorable terms and to construct new infrastructure. One of the major factors that will impact natural gas demand will be the potential growth of the demand for natural gas in the power generation market, particularly driven by the speed and level of existing coal-fired power generation that is replaced with natural gas-fired power generation. One of the major factors impacting domestic natural gas and crude oil supplies has been the significant growth in unconventional sources such as shale plays and the continued progression of hydraulic fracturing technology. The supply and demand for natural gas and crude oil, and therefore the future rate of growth of our business, will depend on these and many other factors outside of our control, including, but not limited to:
- adverse changes in general global economic conditions;
- adverse changes in domestic regulations;
- technological advancements that may drive further increases in production and reduction in costs of developing natural gas shales;
- the price and availability of other forms of energy;
- prices for natural gas, crude oil and NGLs;
- increased costs to explore for, develop, produce, gather, process and transport natural gas or to transport crude oil;
- weather conditions, seasonal trends and hurricane disruptions;
- the nature and extent of, and changes in, governmental regulation, for example greenhouse gas legislation, taxation and hydraulic fracturing;
- perceptions of customers on the availability and price volatility of our services and natural gas and crude oil prices, particularly customers’ perceptions on the volatility of natural gas and crude oil prices over the long term;
- capacity and transportation service into, or out of, our markets; and
- petrochemical demand for NGLs.

We are subject to numerous hazards and operational risks.
Our operations are subject to all the risks and hazards typically associated with transportation, storage and processing of natural gas and the transportation of crude oil. These operating risks include, but are not limited to:
- damage to pipelines, facilities, equipment and surrounding properties caused by hurricanes, earthquakes, tornadoes, floods, fires or other adverse weather conditions and other natural disasters and acts of terrorism;
- inadvertent damage from construction, vehicles, farm and utility equipment;

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

- outages at our processing facilities;
- ruptures, fires, leaks and explosions; and
- other hazards that could also result in personal injury and loss of life, pollution and other environmental risks, and suspension of operations.

For example, on May 4, 2013, we experienced a release of natural gas from a segment of pipeline in Kimball County, Nebraska resulting in damage to a small section of the TIGT pipeline. And, on June 13, 2013, a failure occurred on a small portion of an approximately 33 mile segment of the TIGT pipeline near Torrington, Wyoming, resulting in a release of natural gas.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage. The location of certain segments of our pipeline systems in or near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas could increase the level of damages resulting from these risks. Despite the precautions we take, events such as those described above could cause considerable harm to people or property, could result in loss of service available to customers, and could have a material adverse effect on our financial condition and results of operations and ability to make distributions to unitholders. In addition, maintenance, repair and remediation activities could result in service interruptions on segments of our systems or alter the operational profile of our systems. Potential impacts arising from these service interruptions or operational profile changes on segments of our systems could include, among others, limitations on our ability to satisfy customer requirements, obligations to provide reservation charge credits to customers in times of constrained capacity, and solicitation of existing customers by others for potential new projects that would compete directly with existing services.

We could be required by regulatory authorities to test or undertake modifications to our systems, operations or both that could result in a material adverse impact on our business, financial condition and results of operations. For example, we received a Corrective Action Order from PHMSA on June 19, 2013 directing us to take certain investigative, testing and corrective measures with regard to the segment of the TIGT pipeline that failed on June 13, 2013. Such actions, including those required by PHMSA, could materially and adversely impact our ability to meet contractual obligations and retain customers, with a resulting material adverse impact on our business and results of operations, and could also limit or prevent our ability to make quarterly cash distributions to our unitholders. Some or all of our costs arising from these operational risks may not be recoverable under insurance, contractual indemnification or increases in rates charged to our customers.

Our insurance coverage may not be adequate.

We are not fully insured against all risks inherent to our business, including environmental accidents that might occur. For example, we do not maintain business interruption insurance in the type and amount to cover all possible risks of loss. In addition, we do not carry insurance for certain environmental exposures, including but not limited to potential environmental fines and penalties, business interruption, named windstorm or hurricane exposures and, in limited circumstances, certain political risk exposures. Further, in the event there is a total or partial loss of one or more of our pipeline systems and/or processing facilities, any insurance proceeds that we may receive in respect thereof may not be sufficient in any particular situation to effect a restoration of our pipeline systems and/or processing facilities to the condition that existed prior to such loss. In addition, we do not have insurance coverage on the legal proceedings described in “Note 15 - Legal and Environmental Matters to the consolidated financial statements included in Part II-Item 8.-Financial Statements and Supplementary Data" of our annual report on Form 10-K for the year ended December 31, 2013. The occurrence of any operating risks not fully covered by insurance could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Furthermore, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates, and we may elect to self-insure a portion of our asset portfolio. As a result of market conditions, premiums and deductibles for certain types of insurance policies may substantially increase, and in some instances, certain types of insurance could become unavailable or available only for reduced amounts of coverage. Accordingly, any insurance coverage we do obtain may contain large deductibles or fail to cover certain hazards or cover all potential losses.

Our pipeline integrity program may impose significant costs and liabilities on us, while increased regulatory requirements relating to the integrity of our pipeline systems may require us to make additional capital and operating

expenditures to comply with such requirements.
We are subject to extensive laws and regulations related to pipeline integrity. There are, for example, federal requirements set by PHMSA for owners and operators of natural gas and crude oil pipelines in the areas of pipeline design, construction, and testing, the qualification of personnel and the development of operations and emergency response plans. The rules require pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines and take measures to protect pipeline segments located in what the rules refer to as High Consequence Areas, or HCAs.

Our pipeline operations are subject to pipeline safety regulations administered by PHMSA. These regulations, among other things, include requirements to monitor and maintain the integrity of our pipeline systems and determine the pressures at which our pipeline systems can operate. The Pipeline Safety Act of 2011 enacted January 3, 2012, amends the Pipeline Safety Improvement Act of 2002, or the Pipeline Safety Act of 2002, in a number of significant ways, including:

- reauthorizing funding for federal pipeline safety programs, increasing penalties for safety violations and establishing additional safety requirements for newly constructed pipelines;
- requiring PHMSA to adopt appropriate regulations within two years and requiring the use of automatic or remote-controlled shutoff valves on new or rebuilt pipeline facilities;
- requiring operators of pipelines to verify maximum allowable operating pressure and report exceedances within five days; and
- requiring studies of certain safety issues that could result in the adoption of new regulatory requirements for new and existing pipelines, including changes to integrity management requirements for HCAs, and expansion of those requirements to areas outside of HCAs.

PHMSA published an advanced notice of proposed rulemaking in August 2011 to solicit comments on the need for changes to its safety regulations, including whether to revise integrity management requirements. On August 13, 2012, PHMSA published rules to update pipeline safety regulations to reflect provisions included in the Pipeline Safety Act of 2011, including increasing maximum civil penalties from $0.1 million to $0.2 million per violation per day of violation and from $1.0 million to $2.0 million as a maximum amount for a related series of violations as well as changing PHMSA’s enforcement process.

The ultimate costs of compliance with the integrity management rules are difficult to predict. The majority of the costs to comply with the rules are associated with pipeline integrity testing and the repairs found to be necessary. Changes such as advances of in-line inspection tools, identification of additional threats to a pipeline’s integrity and changes to the amount of pipe determined to be located in HCAs or expansion of integrity management requirements to areas outside of HCAs can have a significant impact on the costs to perform integrity testing and repairs. We plan to continue our pipeline integrity testing programs to assess and maintain the integrity of our existing and future pipelines as required by the DOT rules. 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.

Further, additional laws, regulations and policies that may be enacted or adopted in the future or a new interpretation of existing laws and regulations could significantly increase the amount of these expenditures. For example, PHMSA issued an Advisory Bulletin in May 2012 which advised pipeline operators that they must have records to document the maximum allowable operating pressure for each section of their pipeline and that the records must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing (including hydrotesting) or modifying or replacing facilities to meet the demands of verifiable pressures, could significantly increase our costs. TIGT continues to investigate and, when necessary, report to PHMSA the miles of pipeline for which it has incomplete records for MAOP. We are currently undertaking an extensive internal record review in view of the anticipated PHMSA annual reporting requirements. Additionally, failure to locate such records or verify maximum pressures could require us to operate at reduced pressures, which would reduce available capacity on our natural gas pipeline systems. These specific requirements do not currently apply to crude oil pipelines, but forthcoming regulations implementing the Pipeline Safety Act of 2012 likely will expand the scope of regulation applicable to crude oil pipelines. There can be no assurance as to the amount or timing of future expenditures required to comply with pipeline integrity regulation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, financial position, results of operations and prospects.

In addition, we may be subject to enforcement actions and penalties for failure to comply with pipeline regulations. On August 29, 2012, PHMSA notified TIGT that a report from an audit conducted in 2010 indicated a probable violation for failing to perform a periodic review of personnel responses to certain abnormal operations. Specifically, PHMSA cited to the operation of a relief valve on March 3, 2010. TIGT responded to the notice of probable violation and requested a hearing in a response filed with PHMSA on October 1, 2012. A hearing was held on January 15, 2013 and a Final Order was received on October 30, 2013 that required us to make minor modifications to our operating procedures regarding Abnormal Operating Conditions.

Climate change regulation at the federal, state or regional levels could result in increased operating and capital costs for us.

Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas and products produced from crude oil, are examples of greenhouse gases, or GHGs. Various laws and regulations exist, or are under development that seek to regulate the emission of such GHGs, including United States Environmental Protection Agency, or the

EPA, programs to control GHG emissions and state actions to develop statewide or regional programs. In recent years, the U.S. Congress has considered, but not adopted, legislation to reduce emissions of GHGs.

The EPA published in December 2009 its findings that emissions of GHGs present an endangerment to human health and the environment. Pursuant to this endangerment finding and other rulemakings and interpretations, the EPA concluded that stationary sources would become subject to federal permitting requirements under the Clean Air Act, or CAA, starting in 2011. In 2010, the EPA issued a final rule, known as the "Tailoring Rule," that defines regulatory emission thresholds at which certain new and modified stationary sources are subject to permitting and other requirements for GHG emissions under the CAA's Prevention of Significant Deterioration, or PSD, and Title V programs. The EPA has indicated in rulemakings that it may reduce the current regulatory thresholds for GHGs, making additional sources subject to PSD permitting requirements. On June 23, 2014, the United States Supreme Court ruled that portions of EPA's GHG regulatory program violated the CAA. Specifically, the Supreme Court determined that GHGs cannot independently trigger PSD permitting requirements. However, certain PSD permitting requirements may apply to GHG emissions if emissions of another regulated pollutant, like sulfur dioxide or particulate matter, trigger PSD permitting. Additionally, the Supreme Court ruled that the Tailoring Rule thresholds violated the CAA, while suggesting that EPA could promulgate "de minimis" thresholds for GHGs. Further proceedings are ongoing in the United States Court of Appeals for the District of Columbia.

Some of our facilities emit GHGs in excess of the Tailoring Rule thresholds and have been required to obtain a Title V Permit that reflects this potential to emit GHGs. Although these existing facilities are not currently required to obtain a PSD permit containing enforceable limits on GHG emissions, any future modifications with a potential to emit GHGs above the applicable regulatory thresholds at the time of the application, and emit a regulated non-GHG pollutant in excess of statutory thresholds as well, would require us to obtain a PSD permit containing enforceable limits on GHG emissions. We note that, as described above, the Supreme Court's recent decision on EPA's GHG rules creates some uncertainty regarding applicable regulatory thresholds for GHG emissions for facilities that trigger permitting requirements based on emissions of non-GHG pollutants.

Additional direct regulation of GHG emissions in our industry may be implemented under other CAA programs, including the New Source Performance Standards, or NSPS, program. The EPA has already proposed to regulate GHG emissions from certain electric generating units under the NSPS program. While these proposed regulations for electric generating units would not apply to our operations, the EPA may propose to regulate additional sources under the NSPS program. For example, EPA has committed to propose NSPS regulations for GHG emissions from refineries, which could adversely affect demand for the crude oil that we transport. In addition, in 2009, the EPA published a final rule requiring that specified large GHG emissions sources annually report the GHG emissions for the preceding year in the United States. In 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule for petroleum and natural gas facilities, including natural gas transportation compression facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule requires reporting of GHG emissions by regulated facilities to the EPA on an annual basis. Some of our facilities are required to report under this rule, and operational and/or regulatory changes could require additional facilities to comply with GHG emissions reporting requirements.

At the state level, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHGs, primarily through the planned development of emission inventories or regional greenhouse gas "cap and trade" programs. Many of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. Depending on the particular program, we could be required to purchase and surrender emission allowances and our customers may find it less attractive to produce, own, ship or have natural gas or crude oil processed or refined. Because our operations, including our compressor stations and processing facilities, emit various types of GHGs, primarily methane and carbon dioxide, new legislation or regulation could increase our costs related to operating and maintaining our facilities, and could delay future permitting. Depending on the particular new law, regulation or program adopted, we could be required to incur capital expenditures for installation of new emission controls on our compressor stations and processing facilities, acquire and surrender allowances for our GHG emissions, pay taxes related to our GHG emissions and administer and manage a GHG emissions program. We are not able at this time to estimate such increased costs; however, they could be significant. While we may be able to include some or all of such increased costs in the rates charged by our pipelines, such recovery of costs is uncertain in all cases and may depend on events beyond our control including the outcome of future rate proceedings before the FERC and the provisions of any final legislation or other regulations.

Similarly, while we may be able to recover some or all of such increased costs in the rates charged by our processing facilities, such recovery of costs is uncertain and may depend on the terms of our contracts with our customers. Any of the foregoing could have a material adverse effect on our business, financial position, results of operations and prospects. To the extent financial markets view climate change and greenhouse gas emissions as a financial risk, this could materially and adversely impact our cost of and access to capital. Legislation or regulations that may be adopted to address climate change, or incentives to conserve energy or use alternative energy sources, could also affect the markets for our services by making natural gas products less desirable than competing sources of energy.

Our operations are subject to governmental laws and regulations relating to the protection of the environment, which may expose us to significant costs, liabilities and expenditures that could exceed our current expectations.

Substantial costs, liabilities, delays and other significant issues related to environmental laws and regulations are inherent in natural gas transportation, storage and processing and crude oil transportation operations, and as a result, we may be required to make substantial expenditures that could exceed current expectations. Our operations are subject to extensive federal, state, and local laws and regulations governing health and safety aspects of our operations, environmental protection, including the discharge of materials into the environment, and the security of chemical and industrial facilities. These laws include, but are not limited to, the following:

- CAA and analogous state laws, which impose obligations related to air emissions;
- Clean Water Act, or CWA, and analogous state laws, which regulate discharge of pollutants (Section 402) or fill material (Section 404) from our facilities to state and federal waters, including wetlands;
- Comprehensive Environmental Response, Compenstation, and Liability Act, or CERCLA, and analogous state laws, which regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for disposal;
- Resource Conseravation and Recovery Act, or RCRA, and analogous state laws, which impose requirements for the handling and discharge of hazardous and nonhazardous solid waste from our facilities;
- Occupational Safety and Health Act, or OSHA, which establishes workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances, and appropriate control measures;
- The National Environmental Policy Act, or NEPA, which requires federal agencies to evaluate major agency actions having the potential to significantly impact the environment and which may require the preparation of Environmental Assessments and more detailed Environmental Impact Statements that may be made available for public review and comment;
- The Migratory Bird Treaty Act, or MBTA, which implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds and, pursuant to which the taking, killing or possessing of migratory birds is unlawful without a permit, thereby potentially requiring the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas;
- Endangered Species Act, or ESA, and analogous state laws, which seek to ensure that activities do not jeopardize endangered or threatened animals, fish and plant species, nor destroy or modify the critical habitat of such species;
- Bald and Golden Eagle Protection Act, or BGEPA, prohibits anyone, without a permit issued by the Secretary of the Interior, from “taking” bald or golden eagles, including their parts, nests, or eggs. The Act defines “take” as “pursue, shoot, shoot at, poison, wound, kill, capture, trap, collect, molest or disturb;”
- The Oil Pollution Act, or OPA, and analogous laws, which imposes liability for discharges of oil into waters of the United States and requires facilities which could be reasonably expected to discharge oil into waters of the United States to maintain and implement appropriate spill contingency plans; and
- National Historic Preservation Act, or NHPA, and analogous state laws, which is intended to preserve and protect historical and archeological sites.

Various governmental authorities, including but not limited to the EPA, the U.S. Department of the Interior, the U.S. Department of Homeland Security, and analogous Federal, State and local agencies have the power to enforce compliance with these laws and regulations and the permits and related plans issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws, regulations, permits, plans and agreements may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the imposition of stricter conditions on or revocation of permits, the issuance of injunctions limiting or preventing some or all of our operations, and delays in granting permits.

There is inherent risk of the incurrence of environmental costs and liabilities in our business, some of which may be material, due to our handling of the products we transport and store, air emissions related to our operations, historical industry operations, and waste disposal practices, and the prior use of flow meters and manometers containing mercury. Joint and several, strict liability may be incurred without regard to fault under certain environmental laws and regulations, including but not limited to CERCLA, RCRA and analogous state laws, for the remediation of contaminated areas and in connection with spills or releases of materials associated with oil, natural gas and wastes on, under, or from our properties and facilities. We are currently conducting remediation at several sites to address contamination. For 2014, we have budgeted approximately $576,000 for these ongoing environmental remediation projects. Private parties, including but not limited to the owners of properties through which our pipelines pass and facilities where our wastes are taken for reclamation or disposal, may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws, regulations and permits issued thereunder, or for personal injury or property damage arising from our operations. Some sites at which we operate are located near current or former third-party hydrocarbon storage and processing or natural gas operations or facilities, and there is a risk that contamination has migrated from those sites to ours that could result in remedial action. In addition, increasingly strict laws, regulations and enforcement policies could materially increase our compliance costs and the cost of any remediation that may become necessary. Our insurance does not cover all environmental risks and costs and may not provide sufficient coverage if an environmental claim is made against us.

In June 2013, the EPA extended its National Enforcement Initiatives, enforcement priorities list, including an initiative related to Energy Extraction Activities, for 2014 through 2016. We cannot predict what the results of the current initiative or any future initiative will be, or whether federal, state or local laws or regulations will be enacted in this area. If new regulations are imposed related to oil and gas extraction, the volumes of natural gas and crude oil that we transport and/or process could decline and our results of operations could be materially adversely affected.

Our business may be materially and adversely affected by changed regulations and increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits or plans developed thereunder. Also, we might not be able to obtain or maintain from time to time all required environmental regulatory approvals for our operations, or may have to implement contingencies or conditions in order to obtain such approvals. If there is a delay in obtaining any required environmental regulatory approvals, or if we fail to obtain and comply with them, the operation or construction of our facilities could be prevented or become subject to additional costs, resulting in potentially material adverse consequences to our business, financial condition, results of operations and cash flows.

We are also generally responsible for all liabilities associated with the environmental condition of our facilities and assets, whether acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with certain acquisitions and divestitures, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses, which may not be covered by insurance. In addition, the steps we could be required to take to bring certain facilities into compliance could be prohibitively expensive, and we might be required to shut down, divest or alter the operation of those facilities, which might cause us to incur losses. For example, in August 2011, the U.S. EPA and the WDEQ conducted an inspection of the Leak Detection and Repair (“LDAR”) Program at the Casper Plant in Wyoming. In September 2011, Tallgrass Midstream, LLC received a letter from the U.S. EPA alleging violations of the Standards of Performance of Equipment Leaks for Onshore Natural Gas Processing Plant requirements under the CAA. Tallgrass Midstream, LLC received a letter from the U.S. EPA concerning settlement of this matter in April 2013 and received additional settlement communications from the U.S. EPA and Department of Justice beginning in July 2014. Settlement negotiations are continuing, including attempted resolution of more recently identified LDAR issues. We are not currently able to estimate the costs that may be associated with a settlement or other resolution of this matter, which could be substantial.

We have agreed to a number of conditions in our environmental permits and associated plans, approvals and authorizations that require the implementation of environmental habitat restoration, enhancement and other mitigation measures that involve, among other things, ongoing maintenance and monitoring. Governmental authorities may require, and community groups and private persons may seek to require, additional mitigation measures in the future to further protect ecologically sensitive areas where we currently operate, and would operate if our facilities are extended or expanded, or if we construct new facilities, and we are unable to predict the effect that any such measures would have on our business, financial position, results of operations or prospects.

Further, such existing laws and regulations may be revised or new laws or regulations may be adopted or become applicable to us. In addition to potential GHG regulations, there may also be potential regulations under the NSPS and/or the maximum available control technology standard that may affect us. The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. There can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be materially different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and prospects.

Increased regulation of hydraulic fracturing and other oil and natural gas processing operations could affect our operations and result in reductions or delays in production by our customers, which could have a material adverse impact on our revenues.

A portion of our customers' oil and natural gas production is developed from unconventional sources, such as shales, that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into shale formations to stimulate production. Hydraulic fracturing is currently exempt from federal regulation pursuant to the federal Safe Drinking Water Act, or the SDWA (except when the fracturing fluids or propping agents contain diesel fuels), because hydraulic fracturing is excluded from the SDWA definition of "underground injection" and therefore is not subject to permitting and federal regulatory control pursuant to SDWA. However, public concerns have been raised related to its potential environmental impact. Additional federal, state and local laws and regulations to more closely regulate hydraulic fracturing have been considered and, in some cases, adopted and implemented. For example, from time to time, legislation to further regulate hydraulic fracturing has been proposed in Congress, including repeal of the SDWA exemption for hydraulic fracturing, as well as to require disclosure for chemicals used in hydraulic fracturing. An EPA investigation requested by a committee of the House of Representatives to assess the potential environmental effects of hydraulic fracturing on drinking water and groundwater is underway, with a first progress report outlining work currently underway by the agency released on December 21, 2012 and a final draft report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review in 2014. Reports prepared by the U.S. Department of Energy's Shale Gas Subcommittee could also lead to further restrictions on hydraulic fracturing. In addition, EPA has announced its intention to propose regulations by 2014 under the CWA regarding wastewater discharges from hydraulic fracturing and other gas production and, on May 9, 2014, EPA issued an Advance Notice of Proposed Rulemaking under Section 8 of the Toxic Substances Control Act, or the TSCA, to seek public comment on chemical information that could be reported and disclosed under TSCA.

Apart from federal legislation and EPA regulations, other federal agencies and states have proposed or adopted legislation or regulations restricting hydraulic fracturing. On May 24, 2013, the U.S. Department of Interior published a proposed rule in the Federal Register that includes disclosure requirements and other mandates for hydraulic fracturing on federal lands. Some states have already imposed disclosure requirements associated with hydraulic fracturing, including states in which we operate.

Moreover, some state and local authorities have considered or imposed new laws and rules related to hydraulic fracturing, including additional permit requirements, operational restrictions, chemical disclosure obligations and temporary or permanent bans or, in municipal settings, time, place and manner restrictions, on hydraulic fracturing in certain jurisdictions or in environmentally sensitive areas. For example, Wyoming has imposed regulations regarding disclosure of information regarding chemicals in well stimulation operations. We cannot predict whether any additional federal, state or local laws or regulations will be enacted in this area and if so, what their provisions would be. If additional levels of reporting, regulation or permitting moratoria were required or imposed related to hydraulic fracturing, the volumes of natural gas that we transport could decline and our results of operations could be materially and adversely affected. Further, additional state legislation or regulation may impact our expansion plans by delaying implementation or requiring additional approvals or modifications to expansion plans.

In addition, on April 17, 2012, the EPA approved final rules that establish new air emission controls for oil and natural gas production, pipelines and processing operations. These rules were published in the Federal Register on August 16, 2012 and became effective on October 15, 2012. For new or reworked hydraulically fractured gas wells, the rules require the control of emissions through flaring or reduced emission, or green, completions until 2015, when the rule requires the use of green completions by all such wells except wildcat (exploratory) and delineation gas wells and low reservoir pressure non-wildcat and non-delineation gas wells. The rules also establish specific new requirements regarding emissions from wet seal and reciprocating compressors at production facilities, gathering systems, boosting facilities and onshore natural gas processing plants, effective October 15, 2012, and from pneumatic controllers and storage vessels at production facilities, gathering systems, boosting facilities and onshore natural gas processing plants, effective October 15, 2013. In addition, the rules revise existing requirements for volatile organic compound emissions from equipment leaks at onshore natural gas processing plants by lowering the leak definition for valves from 10,000 parts per million to 500 parts per million and requiring the monitoring of connectors, pumps, pressure relief devices and open-ended lines, effective October 15, 2012. These rules may therefore require a number of modifications to our and our customers' operations, including the installation of new equipment to control emissions. In October 2012 several challenges to EPA's rules were filed by various parties, including environmental groups and industry associations. In a January 1, 2013 unopposed motion to hold this litigation in abeyance, EPA indicated that it may reconsider some aspects of the rule and has since reconsidered certain aspects of the rule. The case is currently in abeyance and EPA may reconsider other aspects of the rule. Depending on the outcome of such proceedings, the rules may be modified or rescinded or EPA may issue new rules, the costs of compliance with any modified or newly issued rules cannot be predicted. Additionally, on December 11, 2012, seven states submitted a notice of intent to sue the EPA to compel the agency to make a determination as to whether standards of performance limiting methane emissions from oil and gas sources are appropriate, and, if so, to promulgate performance standards for methane emissions from the oil and gas sector, which was not addressed in the EPA rule that became effective on October 15, 2012. The notice of intent also requested the EPA issue emission guidelines for the control of methane emissions from existing oil and gas sources. Depending on whether rules are promulgated and the applicability and restrictions in any promulgated rule, compliance with such rules could result in additional costs, including increased capital expenditures and operating costs. While we are not able at this time to estimate such additional costs, as is the case with similarly situated entities in the industry, they could be significant for us. Compliance with such rules may also make it more difficult for our customers to operate, thereby reducing the volume of natural gas transported through our pipelines, which may adversely affect our business. Compliance with such rules could also generally result in additional costs, including increased capital expenditures and operating costs, for us and our customers, which could have a material adverse effect on our business.

Potential Increased Costs As a Result of EPA Regulation of Internal Combustion Engines Could Be Significant.

Internal combustion engines used in our operations are also subject to EPA regulation under the CAA. The EPA published new regulations on emissions of hazardous air pollutants from reciprocating internal combustion engines on August 20, 2010. On January 14, 2013, the EPA signed a final rule amending these regulations and it was published in the Federal Register on January 30, 2013. The EPA also revised the NSPS for stationary compression ignition and spark ignition internal combustion engines on June 28, 2011 and made minor amendments, included in the January 14, 2013 final rule. Compliance with these new regulations may require significant capital expenditures for physical modifications and may require operational changes as well. We are not able to estimate such increased costs, however, as is the case with similarly situated entities in the industry, they could be significant for us.

We are exposed to costs associated with lost and unaccounted for volumes.

A certain amount of natural gas and crude oil may be lost or unaccounted for in normal operations in connection with their transportation across a pipeline system. Under our tariffs and contractual arrangements with our customers we are entitled to retain a specified volume of natural gas and crude oil in order to compensate us for such lost and unaccounted for volumes, as well as the natural gas used to run our natural gas compressor stations, which we refer to collectively as fuel usage. Our pipeline tariffs, other than Trailblazer's, do not contain fuel usage true-up mechanisms; the use of fuel (natural gas, electric and lost and unaccounted for gas) trackers on Trailblazer, while minimizing risk over time, nevertheless leaves Trailblazer exposed to the possibility of under- or over-collections on an annual basis. The level of lost and unaccounted for volumes, and natural gas fuel usage, on our pipeline systems may exceed the natural gas and crude oil volumes retained from our customers as compensation for our lost and unaccounted for volumes, and fuel usage, pursuant to our tariffs and contractual agreements, and it may be necessary to purchase natural gas or crude oil in the market to make up for the difference, which exposes us to commodity price risk. Future exposure to the volatility of natural gas and crude oil prices as a result of lost and unaccounted for volume imbalances could have a material adverse effect on our business, financial condition, results of operations and ability to make quarterly cash distributions to our unitholders.

We have certain long term fixed priced natural gas and crude oil contracts that cannot be adjusted even if our costs increase, and we have certain crude oil contracts that contain favored nation provisions that could require rate decreases if other similarly situated shippers are paying lower rates. As a result our costs could exceed our revenues.

Approximately one-third of our contracted natural gas transportation and storage firm capacity is provided under long-term, fixed price “negotiated rate” contracts that are not subject to adjustment, even if our cost to perform such services exceeds the revenues received from such contracts, and, as a result, our costs could exceed our revenues received under such contracts. It is possible that costs to perform services under our “negotiated rate” contracts will exceed the negotiated rates. If this occurs, it could decrease the cash flow realized by our systems and, therefore, the cash we have available for distributions to our unitholders. Under FERC policy, a regulated service provider and a customer may mutually agree to sign a contract for service at a “negotiated rate,” which is fixed between the natural gas pipeline and the shipper for the contract term and does not necessarily vary with changes in the level of cost-based “recourse rates,” provided that the affected customer is willing to agree to such rates and that the FERC has approved the negotiated rate agreement. These “negotiated rate” contracts are not generally subject to adjustment for increased costs which could be caused by inflation or other factors relating to the specific facilities being used to perform the services. Any shortfall of revenue, representing the difference between “recourse rates” (if higher) and negotiated rates, under current FERC policy, is generally not recoverable from other shippers.

Approximately 90% of our crude oil pipeline capacity is initially being provided to committed shippers under long-term “Throughput and Deficiency Agreements” or “TDAs”. Rates under the TDAs are typically subject to increase only through the FERC annual index process. We generally cannot file for rate increases outside of the annual FERC adjustment process with respect to committed shippers who have signed TDAs. Some of the TDAs also contain favored nations provisions which could result in lower rates being charged to certain committed shippers to ensure that the rates such shippers are paying are no greater than ninety to one hundred percent of the rates being charged to other similarly situated shippers for similar service at similar volumes and terms.

Any significant and prolonged change in or stabilization of natural gas prices could have a negative impact on our natural gas storage business.

Historically, natural gas prices have been seasonal and volatile, which has enhanced demand for our storage services. The natural gas storage business has benefited from significant price fluctuations resulting from seasonal price sensitivity, which impacts the level of demand for our services and the rates we are able to charge for such services. On a system-wide basis, natural gas is typically injected into storage between April and October when natural gas prices are generally lower and withdrawn during the winter months of November through March when natural gas prices are typically higher. However, the market for natural gas may not continue to experience volatility and seasonal price sensitivity in the future at the levels previously seen. If volatility and seasonality in the natural gas industry decrease, because of increased production capacity or otherwise, then demand for our storage services and the prices that we will be able to charge for those services may decline.

In addition to volatility and seasonality, an extended period of high natural gas prices would increase the cost of acquiring base gas and likely place upward pressure on the costs of associated storage expansion activities. Alternatively, an extended period of low natural gas prices could adversely impact storage values for some period of time until market conditions adjust. These commodity price impacts could have a negative impact on our business, financial condition, results of operations and ability to make distributions.

Certain portions of our transportation, storage and processing facilities have been in service for several decades. There could be unknown events or conditions or increased maintenance or repair expenses and downtime associated with our facilities that could have a material adverse effect on our business and results of operations.

Significant portions of our transportation, storage and processing systems have been in service for several decades. The age and condition of our facilities could result in increased maintenance or repair expenditures, and any downtime associated with increased maintenance and repair activities could materially reduce our revenue. Any significant increase in maintenance and repair expenditures or loss of revenue due to the age or condition of our facilities could adversely affect our business and results of operations and our ability to make cash distributions to our unitholders.

Restrictions in our credit facility could adversely affect our business, financial condition, results of operations and ability to make quarterly cash distributions to our unitholders.

Our credit facility limits our ability to, among other things:

- incur or guarantee additional debt;
- redeem or repurchase units or make distributions under certain circumstances;
- make certain investments and acquisitions;
- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates;
- merge or consolidate with another company; and
- transfer, sell or otherwise dispose of assets.

Our credit facility also contains covenants requiring us to maintain certain financial ratios. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot assure you that we will meet those ratios and tests.

The provisions of our credit facility may affect our ability to obtain future financing and pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our credit facility, including a failure to meet the required financial ratios and tests, could result in a default or an event of default that could enable our lenders to restrict or prohibit our ability to make quarterly distributions and declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If the payment of our debt is accelerated, our assets may be insufficient to repay such debt in full, and our unitholders could experience a partial or total loss of their investment.

Our future debt levels may limit our flexibility to obtain financing and to pursue other business opportunities.

Our level of debt could have important consequences to us, including the following:

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

- our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flow required to make interest payments on our debt;

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- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our flexibility in responding to changing business and economic conditions may be limited.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms or at all.

Increases in interest rates could adversely impact demand for our storage capacity, our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

There is a financing cost for our customers to store natural gas in our storage facilities. That financing cost is impacted by the cost of capital or interest rate incurred by the customer in addition to the commodity cost of the natural gas in inventory. Absent other factors, a higher financing cost adversely impacts the economics of storing natural gas for future sale. As a result, a significant increase in interest rates could adversely affect the demand for our storage capacity independent of other market factors.

In addition, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank yield- oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

Difficult conditions in the global capital markets, the credit markets and the economy in general could negatively affect our business and results of operations.

Our business may be negatively impacted by adverse economic conditions or future disruptions in the global financial markets. Included among these potential negative impacts are reduced energy demand and lower prices for our services and increased difficulty in collecting amounts owed to us by our customers which could reduce our access to credit markets, raise the cost of such access or require us to provide additional collateral to our counterparties. Our ability to access available capacity under our credit facility could be impaired if one or more of our lenders fails to honor its contractual obligation to lend to us. If financing is not available when needed, or is available only on unfavorable terms, we may be unable to implement our business plans or otherwise take advantage of business opportunities or respond to competitive pressures.

The amount of cash we have available for distribution to unitholders depends primarily on our cash flow rather than on our profitability, which may prevent us from making distributions, even during periods in which we record net income.

The amount of cash we have available for distribution depends primarily upon our cash flow and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

The lack of diversification of our assets and geographic locations could adversely affect our ability to make distributions to our common unitholders.

We rely primarily on revenues generated from transportation, storage and processing systems that we own, which are primarily located in the Rocky Mountain and Midwest regions of the United States. Due to our lack of diversification in assets and geographic location, an adverse development in these businesses or our areas of operations, including adverse developments due to catastrophic events, weather, regulatory action and decreases in demand for natural gas, could have a significantly greater impact on our results of operations and cash available for distribution to our common unitholders than if we maintained more diverse assets and locations.

We do not own most of the land on which our natural gas and crude oil pipeline systems and Midstream Facilities are located, which could disrupt our operations and subject us to increased costs.

We do not own most of the land on which our pipeline systems and Midstream Facilities have been constructed, and we are therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way, if such rights-of-way lapse or terminate or if our facilities are not properly located within the boundaries of such rights-of-way. For example, the West Frenchie Draw treating facility is located on land leased from the Wyoming Board of Land Commissioners pursuant to a contract that can be terminated at any time. Although many of these rights are perpetual in nature, we occasionally obtain the right to construct and operate pipelines on other owners' land for a specific period of time. If we were to be unsuccessful in renegotiating rights-of-way, we might incur increased costs to maintain our pipeline systems, which could have a material adverse effect on our business, results of operations, financial condition and ability to make distributions to our unitholders. In addition, we are subject to the possibility of increased costs under our rental agreements with landowners, primarily through rental increases and renewals of expired agreements.

Some rights-of-way for our pipeline systems and other real property assets are shared with other pipeline systems and other assets owned by third parties. We or owners of the other pipeline systems may not have commenced or concluded eminent domain proceedings for some rights-of-way. In some instances, lands over which rights-of-way have been obtained are subject to prior liens which have not been subordinated to the right-of-way grants.

Our interstate natural gas pipeline systems have federal eminent domain authority. Whether we have the power of eminent domain for the Pony Express crude oil pipeline varies from state to state, depending upon the laws of the particular state. Regardless, we must compensate landowners for the use of their property, which may include any loss of value to the remainder of their property not being used by us, which are sometimes referred to as "severance damages." Severance damages are often difficult to quantify and their amount can be significant. In eminent domain actions, such compensation may be determined by a court. Our inability to exercise the power of eminent domain could negatively affect our business if we were to lose the right to use or occupy the property on which our crude oil or natural gas pipeline systems are located.

Our operations are dependent on our rights and ability to receive or renew the required permits and other approvals from governmental authorities and other third parties.

Performance of our operations requires that we obtain and maintain numerous environmental and land use permits and other approvals authorizing our business activities. A decision by a governmental authority or other third party to deny, delay or restrictively condition the issuance of a new or renewed permit or other approval, or to revoke or substantially modify an existing permit or other approval, could have a material adverse effect on our ability to initiate or continue operations at the affected location or facility. Expansion of our existing operations is also predicated on securing the necessary environmental or land use permits and other approvals, which we may not receive in a timely manner or at all.

In order to obtain permits and renewals of permits and other approvals in the future, we may be required to prepare and present data to governmental authorities pertaining to the potential adverse impact that any proposed pipeline or processing- related activities may have on the environment, individually or in the aggregate, including on public and Indian lands. Certain approval procedures may require preparation of archaeological surveys, endangered species studies and other studies to assess the environmental impact of new sites or the expansion of existing sites.

Compliance with these regulatory requirements is expensive and significantly lengthens the time needed to develop a site or pipeline alignment. Also, obtaining or renewing required permits or other approvals is sometimes delayed or prevented due to community opposition and other factors beyond our control. The denial of a permit or other approval essential to our operations or the imposition of restrictive conditions with which it is not practicable or feasible to comply could impair or prevent our ability to develop or expand a property or right-of- way. Significant opposition to a permit or other approval by neighboring property owners, members of the public or non- governmental organizations, or other third parties or delay in the environmental review and permitting process also could impair or delay our ability to develop or expand a property or right-of-way. New legal requirements, including those related to the protection of the environment, could be adopted at the federal, state and local levels that could materially adversely affect our operations (including our ability to store, transport or process natural gas or crude oil or the pace of storing, transporting or processing natural gas or crude oil), our cost structure or our customers' ability to use our services. Such current or future regulations could have a material adverse effect on our business and we may not be able to obtain or renew permits or other approvals in the future.

A shortage of skilled labor in the midstream industry could reduce labor productivity and increase costs, which could have a material adverse effect on our business and results of operations.

The transportation, storage and processing of natural gas, the transportation of crude oil and the fractionation of NGLs requires skilled laborers in multiple disciplines such as equipment operators, mechanics and engineers, among others.

If we experience shortages of skilled labor in the future, our labor and overall productivity or costs could be materially and adversely affected. If our labor prices increase or if we experience materially increased health and benefit costs for employees, our results of operations could be materially and adversely affected.

If we fail to develop or maintain an effective system of internal controls, we may not be able to report our financial results accurately or prevent fraud, which would likely have a negative impact on the market price of our common units.

We prepare our financial statements in accordance with GAAP, but our internal accounting controls may not currently meet all standards applicable to companies with publicly traded securities. Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and to operate successfully as a publicly traded partnership. Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future or to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002, which we refer to as Section 404. For example, Section 404 will require us, among other things, to annually review and report on, and our independent registered public accounting firm to attest to, the effectiveness of our internal controls over financial reporting. We must comply with Section 404 (except for the requirement for an auditor's attestation report, as described below) beginning with our fiscal year ending December 31, 2014. Any failure to develop, implement or maintain effective internal controls or to improve our internal controls could harm our operating results or cause us to fail to meet our reporting obligations. Given the difficulties inherent in the design and operation of internal controls over financial reporting, we can provide no assurance as to our, or our independent registered public accounting firm's, conclusions about the effectiveness of our internal controls, and we may incur significant costs in our efforts to comply with Section 404. Ineffective internal controls will subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business and would likely have a negative effect on the trading price of our common units.

For as long as we are an emerging growth company, we will not be required to comply with certain disclosure requirements that apply to other public companies.

In April 2012, President Obama signed into law the Jumpstart Our Business Startups Act, or the JOBS Act. For as long as we remain an “emerging growth company” as defined in the JOBS Act, we intend to continue taking advantage of certain exemptions from various reporting requirements that are applicable to other public companies that are not emerging growth companies, including not being required to provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act and reduced disclosure obligations regarding executive compensation in our periodic reports. We will remain an emerging growth company for up to five years, although we will lose that status sooner if we have more than $1.0 billion of revenues in a fiscal year, have more than $700 million in market value of our limited partner interests held by non-affiliates, or issue more than $1.0 billion of non-convertible debt over a three-year period.

To the extent that we rely on any of the exemptions available to emerging growth companies, you will receive less information about our executive compensation and internal control over financial reporting than issuers that are not emerging growth companies. If some investors find our common units to be less attractive as a result, there may be a less active trading market for our common units and our trading price may be more volatile.

Our election to take advantage of the JOBS Act extended accounting transition period may make our financial statements more difficult to compare to other public companies.

Pursuant to the JOBS Act, as an “emerging growth company,” we must make an election to opt in or opt out of the extended transition period for any new or revised accounting standards that may be issued by the Public Company Accounting Oversight Board (PCAOB) or the SEC. We have elected to take advantage of such extended transition period which means that when a standard is issued or revised and it has different application dates for public or private companies, we can, for so long as we are an “emerging growth company,” adopt the standard for private companies. This may make comparison of our financial statements with any other public company that either is not an “emerging growth company” or has opted out of using the extended transition period difficult or impossible as a result of our use of different accounting standards.

The outcome of future rate cases will determine the amount of income taxes that we will be allowed to recover.

In May 2005, the FERC issued a statement of general policy permitting a pipeline to include in its cost-of-service computations an income tax allowance provided that an entity or individual has an actual or potential income tax liability on income from the pipeline's public utility assets. The extent to which owners of pipelines have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis in rate cases where the amounts of the allowances will be established. An adverse determination by the FERC with respect to this issue could have a material adverse effect on our revenues, earnings and cash flows.

Our business could be negatively impacted by security threats, including cyber security threats, and related disruptions.

We rely on our information technology infrastructure to process, transmit and store electronic information, including information we use to safely operate our assets. We may face cyber security and other security threats to our information technology infrastructure, which could include threats to our operational and safety systems that operate our pipelines, plants and assets. We could face unlawful attempts to gain access to our information technology infrastructure, including coordinated attacks from hackers, whether state-sponsored groups, “hacktivists,” or private individuals. The age, operating systems or condition of our current information technology infrastructure and software assets and our ability to maintain and upgrade such assets could affect our ability to resist cyber security threats. We could also face attempts to gain access to information related to our assets through attempts to obtain unauthorized access by targeting acts of deception against individuals with legitimate access to physical locations or information, otherwise known as “social engineering.”

Our information technology infrastructure is critical to the efficient operation of our business and essential to our ability to perform day-to-day 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, results of operations and prospects.

If we are unable to protect our information and telecommunication systems against disruptions or failures, our operations could be disrupted.

We rely extensively on computer systems to process transactions, maintain information and manage our business. Disruptions in the availability of our computer systems could impact our ability to service our customers and adversely affect our sales and results of operations. We are dependent on internal and third party information technology networks and systems, including the Internet and wireless communications, to process, transmit and store electronic information. Our computer systems are subject to damage or interruption due to system replacements, implementations and conversions, power outages, computer or telecommunication failures, computer viruses, security breaches, catastrophic events such as fires, tornadoes and hurricanes and usage errors by our employees. If our computer systems are damaged or cease to function properly, we may have to make a significant investment to fix or replace them, and we may have interruptions in our ability to service our customers. Although we attempt to eliminate or reduce these risks by using redundant systems, this disruption caused by the unavailability of our computer systems could nevertheless significantly disrupt our operations or may result in financial damage or loss due to, among other things, lost or misappropriated information.

Tax Risks to Common Unitholders

Tax Treatment of Income Earned Through C Corporation Subsidiary

Tallgrass Pony Express Pipeline, LLC owns 99.8% of Tallgrass Pony Express Pipeline (Colorado), Inc. ("PXP Colorado"), which is a C corporation. PXP Colorado is currently in the process of constructing the Northeast Colorado Lateral and has not yet commenced operations or generated any income. However, when PXP Colorado commences operations, a portion of our taxable income will be earned through a C corporation subsidiary. Such C corporation subsidiary is subject to federal income tax on its taxable income at the corporate tax rate, which is currently a maximum of 35%, and will likely pay state (and possibly local) income tax at varying rates, on its taxable income. Any such entity level taxes will reduce the cash available for distribution to our unitholders. Distributions from such C corporation subsidiary will generally be taxed again to unitholders as dividend income to the extent of current and accumulated earnings and profits of such subsidiary. As of January 1, 2014, the maximum federal income tax rate applicable to such dividend income which is allocable to individuals is 20% provided that applicable holding period requirements are satisfied. An individual unitholder's share of dividend and interest income from our C corporation subsidiary would constitute portfolio income that could not be offset by the unitholder's share of our other losses or deductions, except for interest expense properly allocable to borrowed funds to the extent invested in such C corporation subsidiary.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

Item 6. Exhibits

Exhibit No.	Description
10.1	Contribution and Transfer Agreement, dated September 1, 2014, by and among Tallgrass Energy Partners, LP, Tallgrass Operations, LLC and Tallgrass Pony Express Pipeline, LLC (incorporated by reference as Exhibit 10.1 on the Form 8-K filed on September 8, 2014).
10.2	Second Amended and Restated Limited Liability Company Agreement of Tallgrass Pony Express Pipeline, LLC, dated September 1, 2014 (incorporated by reference as Exhibit 10.2 on the Form 8-K filed on September 8, 2014).
10.3*	Amendment No. 1 to Second Amended and Restated Limited Liability Company Agreement of Tallgrass Pony Express Pipeline, LLC, dated as of September 29, 2014, by and among Tallgrass Pony Express Pipeline, LLC, Tallgrass Operations, LLC, and Tallgrass PXP Holdings, LLC.
31.1*	Rule 13a-14(a)/15d-14(a) Certification of David G. Dehaemers, Jr.
31.2*	Rule 13a-14(a)/15d-14(a) Certification of Gary J. Brauchle.
32.1*	Section 1350 Certification of David G. Dehaemers, Jr.
32.2*	Section 1350 Certification of Gary J. Brauchle.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

* -filed herewith

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

		Tallgrass Energy Partners, LP (registrant)	
	By:	Tallgrass MLP GP, LLC, its general partner	
Date: October 30, 2014	By:	/s/ Gary J. Brauchle	
		Name:	Gary J. Brauchle
		Title:	Executive Vice President, Chief Financial Officer and Treasurer