Tallgrass Energy Partners, LP
Form 10-Q
May 03, 2018

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

FORM 10-Q

(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Quarterly Period Ended March 31, 2018
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	46-1972941
(State or other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification Number)
4200 W. 115th Street, Suite 350	
Leawood, Kansas	66211
(Address of Principal Executive Offices)	(Zip Code)

(913) 928-6060
(Registrant's Telephone Number, Including Area Code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer", "accelerated filer", "smaller reporting company", and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the

Exchange Act. ¨
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x
On May 3, 2018, the Registrant had 73,199,753 Common 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.

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.

Commodity sensitive contracts or arrangements: contracts or other arrangements, including tariff provisions, that are directly tied to increases and decreases in the price of commodities such as crude oil, natural gas and NGLs. Examples are Keep Whole Processing Contracts and Percent of Proceeds Processing Contracts, as well as pipeline loss allowances on our pipelines.

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

Contract barrels: barrels of crude oil that our customers have contractually agreed to ship in exchange for firm service assurance of capacity and deliverability to delivery points.

Delivery point: any point at which product in a pipeline is delivered to or for the account of a customer.

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.

EPA: the United States Environmental Protection Agency.

FERC: the United States Federal Energy Regulatory Commission.

Firm fee contracts: contracts or other arrangements, including tariff provisions, that generally obligate our customers to pay a fixed recurring charge to reserve an agreed upon amount of capacity and/or deliverability on our assets, regardless if the contracted capacity is actually used by the customer. Such contracts are also commonly known as "take-or-pay" contracts.

Firm services: services pursuant to which customers receive firm assurances regarding the availability of capacity and/or deliverability of natural gas, crude oil or other hydrocarbons or water on our assets up to a contracted amount.

Fractionation: the process by which NGLs are further separated into individual, typically more valuable components including ethane, propane, butane, isobutane and natural gasoline.

GAAP: accounting principles generally accepted 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.

Interruptible services: services pursuant to which customers receive limited, or no, assurances regarding the availability of capacity and deliverability in our assets.

Keep Whole Processing Contracts: natural gas processing contracts in which we are required to replace the Btu content of the NGLs extracted from inlet wet gas processed with purchased dry natural gas.

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 end users within a specific geographic area.
Long-term: with respect to any contract, a contract with an initial duration greater than one year.
MMBtu: one million British Thermal Units.
Mcf: one thousand cubic feet.
MDth: one thousand dekatherms.
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, 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).
Natural Gas Processing: the separation of natural gas into pipeline-quality natural gas and a mixed NGL stream.
Non-contract barrels (or walk-up barrels): barrels of crude oil that our customers ship based solely 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.
NYSE: New York Stock 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.
Percent of Proceeds Processing Contracts: natural gas processing contracts in which we process our customer's natural gas, sell the resulting NGLs and residue gas and divide the proceeds of those sales between us and the customer. Some percent of proceeds contracts may also require our customers to pay a monthly reservation fee for processing capacity.
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.
Produced water: all water removed from a well as a byproduct of the production of hydrocarbons and water removed from a well in connection with operations being conducted on the well, including naturally occurring water in the recovery formation, flow back water recovered during completion and fracturing operations and water entering the recovery formation through water flooding techniques.
Receipt point: the point where a product is received by or into a gathering system, processing facility, or transportation pipeline.
Reservoir: a porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (such as 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 transportation to end-user markets.
TBtu: one trillion British Thermal Units.

Tcf: one trillion cubic feet.
Throughput: the volume of products, such as crude oil, natural gas or water, transported or passing through a pipeline, plant, terminal or other facility during a particular period.
Uncommitted shippers (or walk-up shippers): customers that have not signed long-term shipper contracts and have rights under the FERC tariff as to rates and capacity allocation that are different than long-term committed shippers.
Volumetric fee contracts: contracts or other arrangements, including tariff provisions, that generally obligate a customer to pay fees based upon the extent to which such customer utilizes our assets for midstream energy services. Unlike firm fee contracts, under volumetric fee contracts our customers are not generally required to pay a charge to reserve an agreed upon amount of capacity and/or deliverability.
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 base 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)

	March 31, 2018	December 31, 2017
	(in thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$4,065	$1,809
Accounts receivable, net	131,401	118,615
Receivable from related parties	4,472	1,340
Gas imbalances	822	1,990
Inventories	32,147	21,609
Derivative assets	306	—
Prepayments and other current assets	10,946	11,175
Total Current Assets	184,159	156,538
Property, plant and equipment, net	2,498,715	2,394,337
Goodwill	404,838	404,838
Intangible assets, net	136,554	97,731
Unconsolidated investments	950,587	909,531
Deferred financing costs, net	11,008	11,684
Deferred charges and other assets	5,018	2,694
Total Assets	$4,190,879	$3,977,353
LIABILITIES AND EQUITY		
Current Liabilities:		
Accounts payable	$119,932	$98,882
Accounts payable to related parties	64	5,461
Gas imbalances	1,616	1,663
Derivative liabilities	—	2,368
Accrued taxes	24,181	19,272
Accrued liabilities	36,894	35,659
Deferred revenue	99,922	88,471
Other current liabilities	7,816	7,171
Total Current Liabilities	290,425	258,947
Long-term debt, net	2,302,014	2,146,993
Other long-term liabilities and deferred credits	19,628	18,965
Total Long-term Liabilities	2,321,642	2,165,958
Commitments and Contingencies		
Equity:		
Limited partners (73,199,753 common units outstanding at March 31, 2018 and December 31, 2017)	2,152,036	2,109,316
General partner (834,391 units outstanding at March 31, 2018 and December 31, 2017)	(640,536)	(625,537)
Total Partners' Equity	1,511,500	1,483,779
Noncontrolling interests	67,312	68,669
Total Equity	1,578,812	1,552,448
Total Liabilities and Equity	$4,190,879	$3,977,353

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
(UNAUDITED)

	Three Months Ended March 31,	
	2018	2017
	(in thousands, except per unit amounts)	
Revenues:		
Crude oil transportation services	$84,738	$84,331
Natural gas transportation services	32,196	31,685
Sales of natural gas, NGLs, and crude oil	38,145	15,381
Processing and other revenues	24,015	13,003
Total Revenues	179,094	144,400
Operating Costs and Expenses:		
Cost of sales	26,351	12,370
Cost of transportation services	10,420	13,503
Operations and maintenance	16,399	12,903
Depreciation and amortization	26,123	21,403
General and administrative	16,367	13,663
Taxes, other than income taxes	8,879	8,226
Gain on disposal of assets	(9,417)	(1,448)
Total Operating Costs and Expenses	95,122	80,620
Operating Income	83,972	63,780
Other Income (Expense):		
Equity in earnings of unconsolidated investments	53,406	20,738
Interest expense, net	(28,184)	(14,689)
Other income, net	451	1,955
Total Other Income (Expense)	25,673	8,004
Net income	109,645	71,784
Net income attributable to noncontrolling interests	(1,761)	(879)
Net income attributable to partners	$107,884	$70,905
Allocation of income to the limited partners:		
Net income attributable to partners	$107,884	$70,905
General partner interest in net income	(41,032)	(30,583)
Net income available to common unitholders	66,852	40,322
Basic net income per common unit	$0.91	$0.56
Diluted net income per common unit	$0.91	$0.55
Basic average number of common units outstanding	73,200	72,544
Diluted average number of common units outstanding	73,675	73,580

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 EQUITY
(UNAUDITED)

	Predecessor Equity	Limited Partners	General Partner	Total Partners' Equity	Noncontrolling Interests	Total Equity
	(in thousands)					
Balance at January 1, 2018	$—	$2,109,316	$(625,537)	$1,483,779	$ 68,669	$1,552,448
Cumulative effect of ASC 606 implementation	—	43,634	497	44,131	—	44,131
Net income	—	66,852	41,032	107,884	1,761	109,645
Issuance of units to public, net of offering costs	—	(45)	—	(45)	—	(45)
Distributions to unitholders	—	(70,638)	(40,376)	(111,014)	—	(111,014)
Noncash compensation expense	—	2,917	—	2,917	—	2,917
Acquisition of additional 2% membership interest in Pony Express	—	—	(16,152)	(16,152)	(33,848)	(50,000)
Consolidation of Deeprock North	—	—	—	—	31,843	31,843
Contributions from noncontrolling interest	—	—	—	—	183	183
Distributions to noncontrolling interest	—	—	—	—	(1,296)	(1,296)
Balance at March 31, 2018	$—	$2,152,036	$(640,536)	$1,511,500	$ 67,312	$1,578,812

	Predecessor Equity	Limited Partners	General Partner	Total Partners' Equity	Noncontrolling Interests	Total Equity
	(in thousands)					
Balance at January 1, 2017	$82,295	$2,070,495	$(632,339)	$1,520,451	$ 33,965	$1,554,416
Acquisition of Terminals and NatGas	(82,295)	—	(57,705)	(140,000)	—	(140,000)
Net income	—	40,322	30,583	70,905	879	71,784
Issuance of units to public, net of offering costs	—	99,373	—	99,373	—	99,373
Distributions to unitholders	—	(58,793)	(29,366)	(88,159)	—	(88,159)
Noncash compensation expense	—	1,882	—	1,882	—	1,882
LTIP units tendered by employees to satisfy tax withholding obligations	—	(400)	—	(400)	—	(400)
Partial exercise of call option	—	(72,381)	(12,561)	(84,942)	—	(84,942)
Repurchase of common units from TD	—	(35,335)	—	(35,335)	—	(35,335)
Acquisition of additional 24.99% membership interest in Rockies Express	—	—	63,681	63,681	—	63,681
Contributions from TD	—		2,301	2,301		2,301
Contributions from noncontrolling interest	—	—	—	—	710	710
Distributions to noncontrolling interest	—	—	—	—	(1,418)	(1,418)
Balance at March 31, 2017	$—	$2,045,163	$(635,406)	$1,409,757	$ 34,136	$1,443,893

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 CASH FLOWS
(UNAUDITED)

	Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Cash Flows from Operating Activities:		
Net income	$109,645	$71,784
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	27,502	23,575
Equity in earnings of unconsolidated investments	(53,406)	(20,738)
Distributions from unconsolidated investments	52,064	20,740
Gain on disposal of assets	(9,417)	(1,448)
Other noncash items, net	148	(1,674)
Changes in components of working capital:		
Accounts receivable and other	(12,015)	2,450
Accounts payable and accrued liabilities	14,775	(5,691)
Deferred revenue	10,750	16,202
Other current assets and liabilities	(1,596)	(819)
Other operating, net	108	(140)
Net Cash Provided by Operating Activities	138,558	104,241
Cash Flows from Investing Activities:		
Acquisition of BNN North Dakota, net of cash acquired	(95,000)	—
Capital expenditures	(58,760)	(26,769)
Sale of Tallgrass Crude Gathering	50,046	—
Acquisition of 38% membership interest in Deeprock North	(19,500)	—
Distributions from unconsolidated investments in excess of cumulative earnings	13,793	10,079
Acquisition of Rockies Express membership interest	—	(400,000)
Acquisition of Terminals and NatGas	—	(140,000)
Other investing, net	(19,616)	(5,352)
Net Cash Used in Investing Activities	(129,037)	(562,042)
Cash Flows from Financing Activities:		
Borrowings under revolving credit facility, net	155,000	552,000
Distributions to unitholders	(111,014)	(88,159)
Acquisition of Pony Express membership interest	(50,000)	—
Proceeds from public offering, net of offering costs	—	99,373
Partial exercise of call option	—	(72,381)
Repurchase of common units from TD	—	(35,335)
Other financing, net	(1,251)	1,628
Net Cash (Used in) Provided by Financing Activities	(7,265)	457,126
Net Change in Cash and Cash Equivalents	2,256	(675)
Cash and Cash Equivalents, beginning of period	1,809	1,873
Cash and Cash Equivalents, end of period	$4,065	$1,198
Schedule of Noncash Investing and Financing Activities:		
Contribution of 38% membership interest in Deeprock North to Deeprock Development	$(19,500)	$—
Issuance of noncontrolling interests in Deeprock Development in exchange for 62% membership interest in Deeprock North	$(31,843)	$—

Increase in accrual for payment of property, plant and equipment	$1,336	$—

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 publicly traded, growth-oriented limited partnership formed to own, operate, acquire and develop midstream energy assets in North America. "We," "us," "our" and similar terms refer to TEP together with its consolidated subsidiaries. Our operations are located in and provide services to certain key United States hydrocarbon basins, including the Denver-Julesburg, Powder River, Wind River, Permian and Hugoton-Anadarko Basins and the Niobrara, Mississippi Lime, Eagle Ford, Bakken, Marcellus, and Utica shale formations. Our reportable business segments are:

- Natural Gas Transportation—the ownership and operation of FERC-regulated interstate natural gas pipelines and integrated natural gas storage facilities;
- Crude Oil Transportation—the ownership and operation of a FERC-regulated crude oil pipeline system; and
- Gathering, Processing & Terminalling—the ownership and operation of natural gas gathering and processing facilities; crude oil storage and terminalling facilities; the provision of water business services primarily to the oil and gas exploration and production industry; the transportation of NGLs; and the marketing of crude oil and NGLs.

Natural Gas Transportation. We provide natural gas transportation and storage services for customers in the Rocky Mountain, Midwest and Appalachian regions of the United States through: (1) our 49.99% membership interest in Rockies Express Pipeline LLC ("Rockies Express"), which owns the Rockies Express Pipeline, a FERC-regulated natural gas pipeline system extending from Opal, Wyoming and Meeker, Colorado to Clarington, Ohio (the "Rockies Express Pipeline") and our 100% membership interest in Tallgrass NatGas Operator, LLC ("NatGas"), which operates the Rockies Express Pipeline, (2) the Tallgrass Interstate Gas Transmission system, a FERC-regulated natural gas transportation and storage system located in Colorado, Kansas, Missouri, Nebraska and Wyoming (the "TIGT System"), and (3) the Trailblazer Pipeline system, a FERC-regulated natural gas pipeline system extending from the Colorado and Wyoming border to Beatrice, Nebraska (the "Trailblazer Pipeline").

Crude Oil Transportation. We provide crude oil transportation to customers in Wyoming, Colorado, and the surrounding regions through Tallgrass Pony Express Pipeline, LLC ("Pony Express"), which owns a FERC-regulated crude oil pipeline commencing in Guernsey, Wyoming and terminating in Cushing, Oklahoma, and includes a lateral in Northeast Colorado commencing in Weld County, Colorado that interconnects with the pipeline just east of Sterling, Colorado (the "Pony Express System"). In the second quarter of 2018, Pony Express placed into service an extension of the system from a new origin near Platteville, Colorado to the Buckingham Terminal.

Gathering, Processing & Terminalling. We provide natural gas gathering and processing services for customers in Wyoming through: (1) a natural gas gathering system in the Powder River Basin (the "Douglas Gathering System"), (2) the Casper and Douglas natural gas processing facilities, and (3) the West Frenchie Draw natural gas treating facility. We also provide NGL transportation services in Northeast Colorado and Wyoming. We perform water business services, including freshwater transportation and produced water gathering and disposal, in Colorado, Texas, Wyoming, and North Dakota through BNN Water Solutions, LLC ("Water Solutions"), and crude oil storage and terminalling services through our 100% membership interest in Tallgrass Terminals, LLC ("Terminals"), which owns and operates crude oil terminals in Colorado, Oklahoma, and Kansas. The Gathering, Processing & Terminalling segment also includes Stanchion Energy, LLC ("Stanchion"), which transacts in crude oil.

The table below summarizes our equity ownership as of March 31, 2018:

Unit holder	Limited Partner Common Units	General Partner Units	Percentage of Outstanding Limited Partner Common Units	Percentage of Outstanding Common and General Partner Units
Public Unitholders	47,580,535	—	65.00 %	64.27 %

Tallgrass Equity, LLC	25,619,218	—	35.00	%	34.60	%
Tallgrass MLP GP, LLC [(1)]	—	834,391	—	%	1.13	%
Total	73,199,753	834,391	100.00	%	100.00	%

[(1)] Tallgrass MLP GP, LLC (the "general partner") also holds all of TEP's incentive distribution rights.

The term "Terminals Predecessor" refers to Terminals and the term "NatGas Predecessor" refers to NatGas prior to their acquisition by TEP on January 1, 2017. Terminals Predecessor and NatGas Predecessor are collectively referred to as 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 Terminals Predecessor and NatGas Predecessor prior to January 1, 2017.

TEGP Merger Agreement

On March 26, 2018, we announced the execution of a definitive Agreement and Plan of Merger (the "Merger Agreement") pursuant to which Tallgrass Energy GP, LP ("TEGP") will acquire the approximately 47.6 million TEP common units held by the public in a share-for-unit merger transaction that is taxable to TEP unitholders for U.S. federal income tax purposes at a ratio of 2.0 TEGP Class A shares for each outstanding TEP common unit. As a result of the proposed transaction, our incentive distribution rights will be cancelled, our common units will no longer be publicly traded, and 100% of our equity interests will be owned by TEGP's subsidiary, Tallgrass Equity, LLC ("Tallgrass Equity") and its subsidiaries. Upon closing of the merger transaction, TEGP will change its name to Tallgrass Energy, LP ("Tallgrass Energy") and will trade on the New York Stock Exchange under the ticker symbol "TGE." Tallgrass Energy will continue to be taxed as a corporation for U.S. federal income tax purposes.

The Merger Agreement has been unanimously approved by the board of directors of TEGP's general partner, the conflicts committee of the board of directors of our general partner, and the board of directors of our general partner. Subject to customary approvals and conditions, including the approval by holders of a majority of the outstanding TEP common units, the merger is expected to close by the end of the second quarter of 2018.

In connection with the proposed transaction, TEGP filed with the Securities and Exchange Commission ("SEC") a registration statement on Form S-4 that included a preliminary proxy statement/prospectus for our unitholders. After the registration statement is declared effective, we will mail a definitive proxy statement/prospectus to our unitholders. The description of the proposed transaction above is not a substitute for the proxy statement/prospectus or registration statement or for any other document that TEGP or TEP may file with the SEC and send to TEGP's and/or TEP's shareholders or unitholders in connection with the proposed transaction. Investors and security holders of TEGP and TEP are urged to read the proxy statement/prospectus and other documents filed with the SEC carefully and in their entirety when they become available because they will contain important information. Investors and security holders will be able to obtain free copies of the proxy statement/prospectus and other documents filed with the SEC by TEGP or TEP through the website maintained by the SEC at http://www.sec.gov. Copies of the documents filed with the SEC by TEGP and TEP will be available free of charge on TEGP's and TEP's website at www.tallgrassenergylp.com, in the "Investor Relations" tab near the top of the page.

2. Summary of Significant Accounting Policies

Basis of Presentation

These condensed consolidated financial statements and related notes for the three months ended March 31, 2018 and 2017 were prepared in accordance with the accounting principles contained in the Financial Accounting Standards Board's Accounting Standards Codification, the single source of accounting principles generally accepted 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 does not include all disclosures required by GAAP for annual periods. The condensed consolidated financial statements for the three months ended March 31, 2018 and 2017 include all normal, recurring adjustments and disclosures that we believe are necessary for a fair statement 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.

Our financial results for the three months ended March 31, 2018 are not necessarily indicative of the results that may be expected for the full year ending December 31, 2018. The accompanying condensed consolidated interim financial statements should be read in conjunction with our audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2017 ("2017 Form 10-K") filed with the SEC on

February 13, 2018.

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. Net income or loss from consolidated subsidiaries that are not wholly-owned by TEP is attributed to TEP and noncontrolling interests in accordance with the respective ownership interests.

TEP closed the acquisition of Terminals and NatGas effective January 1, 2017. As the acquisitions of Terminals and NatGas are considered transactions between entities under common control, and a change in reporting entity, the financial information presented has been recast to include Terminals and NatGas for all periods presented.

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 our 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.

Accounting Pronouncement Recently Adopted

Revenue Recognition

In May 2014, the FASB issued Accounting Standards Update ("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.

Management has completed its evaluation and implemented the revised guidance using the modified retrospective method as of January 1, 2018. This approach allows us to apply the new standard to (i) all new contracts entered into after January 1, 2018 and (ii) all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance as of January 1, 2018 through a cumulative adjustment to members' equity. Consolidated revenues presented in the comparative consolidated financial statements for periods prior to January 1, 2018 will not be revised.

On January 1, 2018, we recorded a cumulative effect adjustment to equity of $44.1 million, increased the carrying amount of our investment in Rockies Express by $42.8 million, and recognized a receivable from Rockies Express of $1.3 million. These adjustments relate to the cumulative effect adjustment recorded by Rockies Express of $125.2 million upon adoption of ASC 606. The cumulative effect adjustment at Rockies Express arose as a result of the allocation of the transaction price to a series of individual performance obligations in certain long-term transportation contracts with tiered-pricing arrangements. The adjustment increases the carrying amount of our investment in Rockies Express to reflect increased equity in earnings and establishes a receivable for the increased management fee revenue that would have been earned by NatGas during the periods prior to implementation.

Through our review process, we also identified the following changes to our revenue recognition policies that did not result in a cumulative effect adjustment on January 1, 2018:

- Gathering & Processing. We have determined that a number of our gathering & processing contracts at TMID do not represent customer arrangements under ASC 606. Instead, arrangements deemed to represent wellhead purchases of raw gas will be accounted for as supply arrangements pursuant to ASC 705. As a result, gathering & processing fees previously recognized in revenue will be reported as a reduction to cost of sales under ASC 606.
-

Pipeline Loss Allowance. We have determined that pipeline loss allowance, or PLA, collected under certain crude oil transportation arrangements is a component of the transaction price where the PLA both significantly exceeds actual losses and was negotiated with the intent of providing a revenue stream to TEP. Under ASC 606, PLA barrels retained from customers will be subject to the guidance for noncash consideration and recognized in revenue at their contract inception fair value.

See Note 11 – Revenue from Contracts with Customers for revenue disclosures related to both the implementation and the additional requirements prescribed by the standard. These new disclosures include information regarding the significant judgments used in evaluating when and how revenue is (or will be) recognized and data related to contract assets and liabilities.

Accounting Pronouncements Not Yet Adopted

ASU No. 2016-02, "Leases (Topic 842)"

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842). ASU 2016-02 provides a comprehensive update to the lease accounting topic in the Codification intended to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The amendments in ASU 2016-02 include a revised definition of a lease as well as certain scope exceptions. The changes primarily impact lessee accounting, while lessor accounting is largely unchanged from previous GAAP.

Management is currently evaluating the impact of our pending adoption of ASC 842. The status of our implementation is as follows:

- Management has formed an implementation team that meets to discuss implementation challenges, technical interpretations, industry-specific treatment of certain contract types, and project status.
- Management is in the process of gathering data and reviewing contracts in order to identify all impacted contracts.
- Management is evaluating the potential information technology and internal control changes that will be required for adoption based on the findings from its contract review process.
- Management plans to provide internal training and awareness related to the revised guidance to the key stakeholders throughout its organization.

The amendments in ASU 2016-02 are effective for public entities for annual reporting periods beginning after December 15, 2018, and for interim periods within that reporting period. Early application is permitted. We are currently evaluating the impact of ASU 2016-02.

3. Acquisitions and Dispositions

Sale of Tallgrass Crude Gathering

In February 2018, we entered into an agreement with an affiliate of Silver Creek Midstream, LLC ("Silver Creek") to sell our 100% membership interest in Tallgrass Crude Gathering, LLC ("TCG"), which owns a 50-mile crude oil gathering system in the Powder River Basin, for approximately $50.0 million. The sale of TCG closed on February 23, 2018. During the three months ended March 31, 2018, we recognized a gain of $9.4 million on the sale which is presented in the line item "Gain on disposal of assets" in the condensed consolidated statements of income.

Iron Horse Joint Venture

In February 2018, we entered into an agreement with Silver Creek to form Iron Horse Pipeline, LLC ("Iron Horse"), a new joint venture pipeline to transport crude oil from the Powder River Basin. During the three months ended March 31, 2018, we contributed an initial $3.5 million and committed to funding our proportionate share of the remaining costs of construction in exchange for a 75% membership interest in Iron Horse. Our investment in Iron Horse is accounted for under the equity method of accounting and reported as "Unconsolidated investments" on the condensed consolidated balance sheets.

Acquisition of Additional 2% Membership Interest in Pony Express

In February 2018, we acquired the remaining 2% membership interest in Pony Express, along with administrative assets consisting primarily of information technology assets, from Tallgrass Development, LP ("TD") for cash consideration of approximately $60 million, bringing our aggregate membership interest in Pony Express to 100%. The acquisition of the remaining 2% membership interest in Pony Express represents a transaction between entities under common control and an acquisition of noncontrolling interests. As a result, financial information for periods prior to the transaction has not been recast to reflect the additional 2% membership interest. The transaction resulted in a deemed distribution to our general partner as discussed further in Note 10 – Partnership Equity and Distributions.

Acquisition of BNN North Dakota

In January 2018, we acquired 100% of the membership interests in Buckhorn Energy Services, LLC and Buckhorn SWD Solutions, LLC, which were subsequently merged and renamed BNN North Dakota, LLC ("BNN North Dakota"), for approximately $95.0 million, net of cash acquired, subject to working capital adjustments. BNN North Dakota owns a produced water gathering and disposal system in the Bakken basin with approximately 133,000 acres under dedication. The transaction qualifies as an acquisition of a business and is accounted for as a business combination under ASC 805.

The following represents the fair value of assets acquired and liabilities assumed (in thousands):

Accounts receivable	$2,457
Inventory	67
Property, plant and equipment	48,900
Intangible asset	46,800 (1)
Accounts payable and accrued liabilities	(3,224)
Net identifiable assets acquired (excluding cash)	$95,000

(1) The $46.8 million intangible asset acquired represents three major customer relationships. This intangible asset is amortized on a straight-line basis over a period of 8 - 14 years, the remaining terms of the underlying contracts at the time of acquisition.

At March 31, 2018, the assets acquired and liabilities assumed in the acquisition were recorded at provisional amounts based on the preliminary purchase price allocation. We are in the process of identifying and measuring 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 income attributable to TEP from BNN North Dakota of $3.1 million and $1.7 million, respectively, was recognized in the accompanying condensed consolidated statements of income for the period from January 12, 2018 to March 31, 2018.

Pro Forma Financial Information

Unaudited pro forma revenue and net income attributable to TEP for the three months ended March 31, 2018 and 2017 is presented below as if the acquisition of BNN North Dakota had been completed on January 1, 2017.

	Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Revenue	$179,522	$146,716
Net income attributable to partners	$108,116	$70,061

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 transaction had in fact occurred on the date or for the period indicated, nor does it 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 transaction or the costs to achieve these cost savings, operating synergies, and revenue enhancements.

Acquisition of Deeprock North and Merger with Deeprock Development

In January 2018, Terminals acquired an approximate 38% membership interest in Deeprock North, LLC ("Deeprock North") from Kinder Morgan Deeprock North Holdco LLC for cash consideration of $19.5 million. Immediately following the acquisition, Deeprock North was merged into Deeprock Development, LLC ("Deeprock Development"), and the members of Deeprock North and Deeprock Development received adjusted membership interests in the combined entity. As a result, Terminals recognized additional noncontrolling interests in Deeprock Development of $31.8 million. The acquisition of Deeprock North by Deeprock Development has been accounted for as an asset acquisition, with substantially all of the fair value allocated to the long-lived assets acquired based on their relative fair values. After the acquisition and merger, Terminals owns an approximate 60% membership interest in the combined entity.

4. Related Party Transactions

As a result of our relationship with Tallgrass Energy Holdings, LLC ("Tallgrass Energy Holdings") and its affiliates, we have entered into a number of related party transactions. The following disclosure includes those related party transactions which are not otherwise disclosed in these notes to our condensed consolidated financial statements.

We have no employees. In connection with the closing of our initial public offering on May 17, 2013, TEP and its general partner entered into an Omnibus Agreement with Tallgrass Energy Holdings and certain of its affiliates (the "TEP Omnibus Agreement"). The TEP Omnibus Agreement provides that, among other things, TEP will reimburse Tallgrass Energy Holdings 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 Tallgrass Energy Holdings and its affiliates, 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.
Totals of transactions with affiliated companies, excluding transactions disclosed elsewhere in these notes, are as follows:

	Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Processing and other revenues [1]	$1,896	$1,632
Cost of transportation services [2]	$—	$4,507
Charges to TEP: [3]		
Property, plant and equipment, net	$—	$293
Operations and maintenance	$—	$6,277
General and administrative	$—	$9,377

(1) Reflects the fee that NatGas receives as the operator of the Rockies Express Pipeline.

(2) Reflects rent expense for the crude oil storage at the Deeprock Terminal prior to our consolidation of Deeprock Development during the third quarter of 2017.

(3) Charges to TEP include indirectly charged wages and salaries, other compensation and benefits, and shared services for periods prior to January 1, 2018. Effective January 1, 2018, these costs are incurred by TEP directly and, in the case of certain employee compensation and benefits, paid on TEP's behalf by its affiliate, Tallgrass Management, LLC pursuant to the TEP Omnibus Agreement.

Details of balances with affiliates included in "Receivable from related parties" and "Accounts payable to related parties" in the condensed consolidated balance sheets are as follows:

	March 31, 2018	December 31, 2017
	(in thousands)	
Receivable from related parties:		
Rockies Express Pipeline LLC	$4,324	$ 1,340
Iron Horse Pipeline, LLC	148	—
Total receivable from related parties	$4,472	$ 1,340
Accounts payable to related parties:		
Tallgrass Operations, LLC [1]	$—	$ 5,381
Tallgrass Equity, LLC	64	80
Total accounts payable to related parties	$64	$ 5,461

(1) Reflects accounts payable for charges to TEP including indirectly charged wages and salaries, other compensation and benefits, and shared services prior to January 1, 2018 as discussed above.

Gas imbalances with affiliated shippers are as follows:

	March 31, 2018	December 31, 2017
	(in thousands)	

Affiliate gas imbalance receivables	$13	$ 18
Affiliate gas imbalance payables	$269	$ 442

5. Inventory

The components of inventory at March 31, 2018 and December 31, 2017 consisted of the following:

	March 31, 2018	December 31, 2017
	(in thousands)	
Crude oil	$21,517	$ 12,792
Materials and supplies	5,914	5,891
Natural gas liquids	607	942
Gas in underground storage	4,109	1,984
Total inventory	$32,147	$ 21,609

6. Property, Plant and Equipment

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

	March 31, 2018	December 31, 2017
	(in thousands)	
Crude oil pipelines	$1,252,262	$1,220,379
Gathering, processing and terminalling assets [1]	744,515	675,092
Natural gas pipelines	585,483	581,400
General and other	118,355	98,680
Construction work in progress	112,464	97,978
Accumulated depreciation and amortization	(314,364)	(279,192)
Total property, plant and equipment, net	$2,498,715	$2,394,337

(1) Includes approximately $46.2 million and $40.1 million of assets associated with the acquisitions of Deeprock North and BNN North Dakota, respectively, in January 2018.

7. Investments in Unconsolidated Affiliates

Our investment in Rockies Express is recorded under the equity method of accounting and is reported as "Unconsolidated investments" on our condensed consolidated balance sheets. During the three months ended March 31, 2018, we recognized equity in earnings associated with our 49.99% membership interest in Rockies Express of $52.1 million, inclusive of the amortization of the negative basis difference, and received distributions from and made contributions to Rockies Express of $65.9 million and $2.4 million, respectively.

Summarized financial information for Rockies Express is as follows:

	Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Revenue	$230,058	$201,338
Operating income	$128,678	$107,369
Net income to Members	$90,968	$66,250

8. Risk Management

We enter into derivative contracts with third parties for the purpose of hedging exposures that accompany our normal business activities. Our normal business activities directly and indirectly expose us to risks associated with changes in the market price of crude oil and natural gas, among other commodities. For example, the risks associated with changes in the market price of crude oil and natural gas include, among others (i) pre-existing or anticipated physical crude oil and natural gas sales, (ii) natural gas purchases and (iii) natural gas system use and storage. We have 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 our derivative contracts included in the condensed consolidated balance sheets:

	Balance Sheet Location	March 31, 2018	December 31, 2017
		(in thousands)	
Crude oil derivative contracts (1)	Current assets	$ 306	$ —
Crude oil derivative contracts (1)	Current liabilities	$ —	$ 2,368

(1) As of March 31, 2018, the fair value shown for crude oil derivative contracts represents the forward sale of 242,000 barrels which will settle throughout the second quarter of 2018. As of December 31, 2017, the fair value shown for crude oil derivative contracts represents the forward sale of 356,000 barrels of crude oil which settled in the first quarter of 2018.

Effect of Derivative Contracts in the Statements of Income

The following table summarizes the impact of derivative contracts not designated as hedging contracts for the three months ended March 31, 2018 and 2017:

	Location of gain recognized in income on derivatives	Amount of gain recognized in income on derivatives Three Months Ended March 31,	
		2018	2017
		(in thousands)	
Derivatives not designated as hedging contracts:			
Crude oil derivative contracts	Sales of natural gas, NGLs, and crude oil	$ 4,295	$ 663
Natural gas derivative contracts	Sales of natural gas, NGLs, and crude oil	$ —	$ 173
Call option derivative	Other income, net	$ —	$ 1,885

Call Option Derivative

As part of our acquisition of an additional 31.3% membership interest in Pony Express effective January 1, 2016, TD granted us an 18 month call option at an exercise price of $42.50 per common unit covering the 6,518,000 common units issued to TD as a portion of the consideration. On February 1, 2017, we exercised the remainder of the call option covering an additional 1,703,094 common units for a cash payment of $72.4 million. These common units were deemed canceled upon the exercise of the call option and as of the applicable exercise date were no longer issued and outstanding.

Credit Risk

We have counterparty credit risk as a result of our use of derivative contracts. Counterparties to our commodity derivatives consist of market participants and major financial institutions. This concentration of counterparties may impact our 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. The counterparty to our call option derivative was TD.

Our derivative contracts are entered into with counterparties through central trading organizations such as futures, options or stock exchanges or counterparties outside of central trading organizations. While we typically enter into derivative transactions with investment grade counterparties and actively monitor their credit ratings, it is nevertheless possible that from time to time losses will result from counterparty credit risk in the future. The maximum potential exposure to credit losses on our crude oil derivative contracts at March 31, 2018 was:

	Asset Position (in thousands)
Gross	$ 306
Netting agreement impact	—
Cash collateral held	—
Net exposure	$ 306

As of March 31, 2018 and December 31, 2017, we had $0.8 million and $3.0 million, respectively, of cash in margin accounts and outstanding letters of credit in support of our commodity derivative contracts.

Fair Value

Derivative assets and liabilities are measured and reported at fair value. Derivative contracts can be exchange-traded or over-the-counter ("OTC"). OTC commodity 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. We use 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. The call option granted by TD was valued using a Black-Scholes option pricing model. Key inputs to the valuation model included the term of the option, risk free rate, the exercise price and current market price, expected volatility and expected distribution yield of the underlying units. The call option valuation was classified within Level 2 of the fair value hierarchy as the value was based on significant observable inputs.

The following table summarizes the fair value measurements of our derivative contracts as of March 31, 2018 and December 31, 2017, based on the fair value hierarchy:

	Total	Asset Fair Value Measurements Using		
		Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
	(in thousands)			
As of March 31, 2018:				
Crude oil derivative contracts	$306	$ —	$ 306	$ —

	Total	Liability Fair Value Measurements Using		
		Quoted prices in active markets for	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)

		identical assets (Level 1)		
	(in thousands)			
As of December 31, 2017:				
Crude oil derivative contracts	$2,368	$ —	$ 2,368	$ —

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9. Long-term Debt

Long-term debt consisted of the following at March 31, 2018 and December 31, 2017:

	March 31, 2018	December 31, 2017
	(in thousands)	
Revolving credit facility	$816,000	$661,000
5.50% senior notes due September 15, 2024	750,000	750,000
5.50% senior notes due January 15, 2028	750,000	750,000
Less: Deferred financing costs, net [1]	(17,628)	(17,737)
Plus: Unamortized premium on 2028 Notes	3,642	3,730
Total long-term debt, net	$2,302,014	$2,146,993

(1) Deferred financing costs, net as presented above relate solely to the 2024 and 2028 Notes. Deferred financing costs associated with our revolving credit facility are presented in noncurrent assets on our condensed consolidated balance sheets.

Senior Unsecured Notes due 2028

On September 15, 2017, TEP and Tallgrass Energy Finance Corp. (the "Co-Issuer" and together with TEP, the "Issuers"), the Guarantors named therein and U.S. Bank, National Association, as trustee, entered into an Indenture dated September 15, 2017 (the "2028 Indenture") pursuant to which the Issuers issued $500 million in aggregate principal amount of 5.50% senior notes due 2028 (the "2028 Notes"). On December 11, 2017, the Issuers issued an additional $250 million in aggregate principal amount of the 2028 Notes, which are also governed by the 2028 Indenture. The notes issued on September 15, 2017 and December 11, 2017 are treated as a single class of debt securities and have identical terms, other than the issue date and offering price.

The 2028 Indenture contains covenants that, among other things, limit TEP's ability and the ability of its restricted subsidiaries to: (i) create liens to secure indebtedness; (ii) enter into sale-leaseback transactions; and (iii) consolidate with or merge with or into, or sell substantially all TEP's properties to, another person. As of March 31, 2018, we were in compliance with the covenants required under the 2028 Notes.

Senior Unsecured Notes due 2024

On September 1, 2016, the Issuers, the Guarantors named therein and U.S. Bank, National Association, as trustee, entered into an Indenture dated September 1, 2016 (the "2024 Indenture"), pursuant to which the Issuers issued $400 million in aggregate principal amount of 5.50% senior notes due 2024 (the "2024 Notes"). On May 16, 2017, the Issuers issued an additional $350 million in aggregate principal amount of the 2024 Notes which are also governed by the 2024 Indenture. The notes issued on September 1, 2016 and May 16, 2017 are treated as a single class of debt securities and have identical terms, other than the issue date, offering price and first interest payment date.

The 2024 Indenture contains covenants that, among other things, limit TEP's ability and the ability of its restricted subsidiaries to: (i) incur, assume or guarantee additional indebtedness or issue preferred units; (ii) create liens to secure indebtedness; (iii) pay distributions on equity interests in the event of default or noncompliance with the covenants required, repurchase equity securities or redeem subordinated securities; (iv) make investments; (v) restrict distributions, loans or other asset transfers from TEP's restricted subsidiaries; (vi) consolidate with or merge with or into, or sell substantially all of TEP's properties to, another person; (vii) sell or otherwise dispose of assets, including equity interests in subsidiaries; and (viii) enter into transactions with affiliates. As of March 31, 2018, we were in compliance with the covenants required under the 2024 Notes.

Revolving Credit Facility

The following table sets forth the available borrowing capacity under the revolving credit facility as of March 31, 2018 and December 31, 2017:

	March 31, 2018	December 31, 2017
	(in thousands)	
Total capacity under the revolving credit facility	$1,750,000	$1,750,000
Less: Outstanding borrowings under the revolving credit facility	(816,000)	(661,000)
Less: Letters of credit issued under the revolving credit facility	(94)	(94)
Available capacity under the revolving credit facility	$933,906	$1,088,906

The revolving 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 therefrom, 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." In addition, we are required to maintain a consolidated leverage ratio of not more than 5.00 to 1.00 (which will be increased to 5.50 to 1.00 for certain measurement periods following the consummation of certain acquisitions), a consolidated senior secured leverage ratio of not more than 3.75 to 1.00 and a consolidated interest coverage ratio of not less than 2.50 to 1.00. As of March 31, 2018, we were in compliance with the covenants required under the revolving credit facility. The unused portion of the revolving credit facility is subject to a commitment fee, which ranges from 0.250% to 0.500%, based on our total leverage ratio. As of March 31, 2018, the weighted average interest rate on outstanding borrowings under the revolving credit facility was 3.27%. During the three months ended March 31, 2018, our weighted average effective interest rate, including the interest on outstanding borrowings under the revolving credit facility, commitment fees, and amortization of deferred financing costs, was 3.53%.

Fair Value

The following table sets forth the carrying amount and fair value of our long-term debt, which is not measured at fair value in the condensed consolidated balance sheets as of March 31, 2018 and December 31, 2017, 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)				
As of March 31, 2018:					
Revolving credit facility	$—	$ 816,000	$ —	$816,000	$816,000
2024 Notes	$—	$ 767,063	$ —	$767,063	$740,202
2028 Notes	$—	$ 754,425	$ —	$754,425	$745,812
As of December 31, 2017:					
Revolving credit facility	$—	$ 661,000	$ —	$661,000	$661,000
2024 Notes	$—	$ 771,645	$ —	$771,645	$739,824
2028 Notes	$—	$ 758,168	$ —	$758,168	$746,169

The long-term debt borrowed under the revolving credit facility is carried at amortized cost. As of March 31, 2018 and December 31, 2017, the fair value of borrowings under the revolving credit facility approximates the carrying amount of the borrowings using a discounted cash flow analysis. The 2024 and 2028 Notes are carried at amortized cost, net of deferred financing costs. The estimated fair value of the 2024 and 2028 Notes is based upon quoted market prices adjusted for illiquid markets. We are not aware of any factors that would significantly affect the estimated fair value subsequent to March 31, 2018.

10. Partnership Equity and Distributions

Equity Distribution Agreements

We have active equity distribution agreements pursuant to which we may sell from time to time through a group of managers, as our sales agents, common units representing limited partner interests having an aggregate offering price of up to $100.2 million and $657.5 million. Net cash proceeds from any sale of the common units may be used for general partnership purposes, which includes, among other things, the Partnership's exercise of the call option with respect to the 6,518,000 common units issued to TD in connection with the Partnership's acquisition of an additional 31.3% of Pony Express in January 2016, repayment or refinancing of debt, funding for acquisitions, capital expenditures and additions to working capital. During the three months ended March 31, 2018, we did not issue any common units under our equity distribution agreements.

During the three months ended March 31, 2017, we issued and sold 2,087,647 common units with a weighted average sales price of $48.23 per unit under our equity distribution agreements for net cash proceeds of approximately $99.4 million (net of approximately $1.3 million in commissions and professional service expenses).

Repurchase of Common Units Owned by TD

Following an offer received from TD with respect to common units owned by TD not subject to the call option, we repurchased 736,262 common units from TD at an aggregate price of approximately $35.3 million, or $47.99 per common unit, on February 1, 2017, which was approved by the conflicts committee of the board of directors of our general partner. These common units were deemed canceled upon our purchase and as of such transaction date were no longer issued and outstanding.

Distributions to Holders of Common Units, General Partner Units and Incentive Distribution Rights

The following table shows the distributions for the periods indicated:

Three Months Ended	Date Paid	Distributions Limited Partner Common Units	General Partner Incentive Distribution Rights	General Partner Units	Total	Distribution per Limited Partner Common Unit
		(in thousands, except per unit amounts)				
March 31, 2018	May 15, 2018 (1)	$71,370	$39,816	$1,267	$112,453	$ 0.9750
December 31, 2017	February 14, 2018	70,638	39,125	1,251	111,014	0.9650
September 30, 2017	November 14, 2017	69,174	37,744	1,219	108,137	0.9450
June 30, 2017	August 14, 2017	67,671	36,342	1,186	105,199	0.9250
March 31, 2017	May 15, 2017	60,486	29,840	1,040	91,366	0.8350

(1) The distribution announced on March 26, 2018 for the first quarter of 2018 will be paid on May 15, 2018 to unitholders of record at the close of business on April 30, 2018.

Other Contributions and Distributions

During the three months ended March 31, 2018, TEP recognized the following other contributions and distributions:

- TEP was deemed to have made a noncash capital distribution of $16.2 million to the general partner, which represents the excess purchase price over the carrying value of the additional 2% membership interest in Pony Express acquired February 1, 2018; and
- TEP recognized distributions to and contributions from noncontrolling interests of $1.3 million and $0.2 million, respectively.

During the three months ended March 31, 2017, TEP recognized the following other contributions and distributions:

- TEP was deemed to have made a noncash capital distribution of $57.7 million to the general partner, which represents the excess purchase price over the carrying value of the Terminals and NatGas net assets acquired January 1, 2017;
- TEP was deemed to have made a noncash capital distribution of $12.6 million to the general partner, which represents the derecognition of a portion of the derivative asset associated with the partial exercise of the call option;
- TEP was deemed to have received a noncash capital contribution of $63.7 million from the general partner, which represents the excess carrying value of the additional 24.99% membership interest in Rockies Express acquired March 31, 2017 over the fair value of the consideration paid;

- TEP received contributions from TD of $2.3 million primarily to indemnify TEP for costs associated with Trailblazer's Pipeline Integrity Management Program, as discussed in Note 14 – Legal and Environmental Matters; and
- TEP recognized contributions from and distributions to noncontrolling interests of $0.7 million and $1.4 million, respectively, which primarily consisted of activity associated with TD's 2% noncontrolling interest in Pony Express.

11. Revenue from Contracts with Customers

Implementation of ASC Topic 606

As discussed in Note 2 – Summary of Significant Accounting Policies, we adopted the guidance in ASC Topic 606 effective January 1, 2018 using the modified retrospective method of adoption. As a result, revenue reported for the three months ended March 31, 2017 has not been revised. The following tables provide the impact of the guidance on our condensed consolidated balance sheet as of March 31, 2018 and the condensed consolidated statement of income for the three months ended March 31, 2018:

	March 31, 2018		
	As currently reported	Under previous guidance	Impact of ASC Topic 606
	(in thousands)		
Unconsolidated investments	$950,587	$900,013	$50,574 (1)

	Three Months Ended March 31, 2018		
	As currently reported	Under previous guidance	Impact of ASC Topic 606
	(in thousands)		
Revenues:			
Crude oil transportation services	$84,738	$84,466	$272 (2)
Sales of natural gas, NGLs, and crude oil	$38,145	$39,245	$(1,100) (3)
Processing and other revenues	$24,015	$25,525	$(1,510) (1)(3)
Cost of sales	$26,351	$28,845	$(2,494) (2)(3)
Equity in earnings of unconsolidated investments	$53,406	$45,698	$7,708 (1)
Net income attributable to partners	$107,884	$100,020	$7,864
Basic net income per common unit	$0.91	$0.80	$0.11
Diluted net income per common unit	$0.91	$0.80	$0.11

(1) Reflects the impact on our investment in Rockies Express and the management fee collected by NatGas of the cumulative effect adjustment at Rockies Express, which arose as a result of the allocation of the transaction price to a series of individual performance obligations in certain long-term transportation contracts with tiered-pricing arrangements. The adjustment increases the carrying amount of our investment in Rockies Express to reflect increased equity in earnings and establishes a receivable for the increased management fee revenue that would have been earned by NatGas.

(2) Reflects the impact to revenue and cost of sales to value PLA barrels collected under certain crude oil transportation arrangements at their contract inception fair value in revenue and record an associated lower of cost or net realizable value adjustment in cost of sales.

(3) Reflects the reclassification of certain gathering and processing fees collected under arrangements determined to be supply arrangements, rather than customer arrangements under ASC 606, to cost of sales and the reclassification of certain commodities retained as consideration for processing services to processing fee revenue.

Disaggregated Revenue

A summary of our revenue by line of business is as follows:

	Three Months Ended March 31, 2018				
	Natural Gas Transportation segment	Crude Oil Transportation segment	Gathering, Processing, & Terminalling segment	Corporate and Other	Total Revenue
	(in thousands)				
Crude oil transportation - committed shipper revenue	$—	$ 84,738	$ —	$—	$84,738
Natural gas transportation - firm service	33,334	—	—	(1,883)	31,451
Water business services	—	—	13,204	—	13,204
Natural gas gathering & processing fees	—	—	5,044	—	5,044
All other [1]	2,630	3,319	5,706	(6,088)	5,567
Total service revenue	35,964	88,057	23,954	(7,971)	140,004
Natural gas liquids sales	—	—	23,609	—	23,609
Natural gas sales	238	—	7,847	—	8,085
Crude oil sales	—	1,909	247	—	2,156
Total commodity sales revenue	238	1,909	31,703	—	33,850
Total revenue from contracts with customers	36,202	89,966	55,657	(7,971)	173,854
Other revenue [2]	—	—	8,181	(2,941)	5,240
Total revenue [3]	$36,202	$ 89,966	$ 63,838	$(10,912)	$179,094

(1) Includes revenue from crude oil terminal services, interruptible natural gas transportation and storage, and natural gas park and loan service.

(2) Includes lease and derivative revenue not subject to ASC 606.

(3) Excludes $230.1 million of revenue recognized at Rockies Express for the three months ended March 31, 2018. See Note 7 – Investments in Unconsolidated Affiliates for additional information about our investment in Rockies Express.

Performance Obligations

A performance obligation is a promise in a contract to transfer a distinct good or service to the customer, and is the unit of account in ASC Topic 606. A contract's transaction price is allocated to each distinct performance obligation and recognized as revenue when, or as, the performance obligation is satisfied. The majority of our contracts have a single performance obligation and are billed and collected monthly.

All of our segments engage in commodity sales, in which our performance obligations include an obligation to deliver the specified volume of a commodity to the designated receipt point. Revenue from commodity sales is recognized at a point in time when the customer obtains control of the commodity, typically upon delivery to the designated delivery point when the customer accepts and takes possession of the commodity.

In the Natural Gas Transportation segment, our performance obligations typically include an obligation to stand ready to provide natural gas transportation, storage, or an integrated transportation and storage service over the life of the contract, which is a series. These performance obligations are satisfied over time using each day of service to measure progress toward satisfaction of the performance obligation.

In the Crude Oil Transportation segment, our performance obligations typically include an obligation to provide crude oil transportation services over the life of the contract, which is a series. These performance obligations are satisfied over time using barrels delivered to measure progress toward satisfaction of the performance obligation.

In the Gathering, Processing & Terminalling segment, the performance obligations vary based on the operating asset and type of contract. In our natural gas gathering and processing arrangements, performance obligations typically include an obligation to provide an integrated processing service over the life of the contract, which is a series. These performance obligations are satisfied over time using each unit of gas processed to measure progress toward satisfaction of the performance obligation. In our freshwater supply arrangements, performance obligations typically include an obligation to deliver a specified volume of water to the designated receipt point. These performance obligations are satisfied at a point in time when the customer obtains control of the water. In our produced water gathering and disposal arrangements, performance obligations typically include an obligation to provide an integrated produced water gathering and disposal service over the life of the contract, which is a series. These performance obligations are satisfied over time using barrels disposed to measure progress toward satisfaction of the performance obligation.

On March 31, 2018, we had $1.7 billion of remaining performance obligations at our consolidated subsidiaries, which we refer to as total backlog. Total backlog includes performance obligations under long-term crude oil transportation contracts with committed shippers, natural gas firm transportation and firm storage contracts, and certain water business service contracts with minimum volume commitments, and excludes variable consideration that is not estimated at contract inception, as discussed further below. We expect to recognize the total backlog during the remainder of 2018 and future periods as follows (in thousands):

Year	Estimated Revenue
2018	$387,826
2019	488,919
2020	317,235
2021	138,686
2022	129,548
Thereafter	271,311
Total	$1,733,525

Contract Estimates

Accounting for long-term contracts involves the use of various techniques to estimate total contract revenue. Contract estimates are based on various assumptions to project the outcome of future events that often span several years. These assumptions include the anticipated volumes of crude oil expected to be delivered by our customers for transport in future periods.

The nature of our contracts gives rise to several types of variable consideration, including PLA, volumetric charges for actual volumes delivered, overrun charges, and other fees that are contingent on the actual volumes delivered by our customers. As the amount of variable consideration is allocable to each distinct performance obligation within the series of performance obligations that comprise the single performance obligation, we do not estimate the total variable consideration for the single overall performance obligation because the uncertainty related to the consideration is resolved each month as the distinct service is provided. Consequently, we are able to include in the transaction price each month the actual amount of variable consideration because no uncertainty exists surrounding the services provided that month.

Certain of our contracts include provisions in which a portion of the consideration is noncash. In our Crude Oil Transportation segment, we collect PLA from our customers. As crude oil is transported, we earn, and take title to, a portion of the oil transported for our services. Any PLA that remains after replacing losses in transit can be sold. Where PLA is determined to be a component of compensation for the transportation services provided, crude oil retained is recognized in revenue at its contract inception fair value. In our Gathering, Processing & Terminalling segment, we retain commodity products as consideration under certain of our gathering and processing arrangements. Processing fee revenue is recorded when the performance obligation is completed based on the value of the product received at the time services are performed. At this time, the variability of the non-cash consideration related to both form (price) and other-than-form (volume and product mix), which are interrelated, is resolved.

As a significant change in one or more of these estimates could affect the amount and timing of revenue recognized under our customer contracts, we review and update our contract-related estimates regularly.

Contract Balances

The timing of revenue recognition, billings, and cash collections may result in billed accounts receivable, unbilled receivables (contract assets), and deferred revenue (contract liabilities) on our condensed consolidated balance sheets. Revenue is generally billed and collected monthly based on services provided or commodity volumes sold. In our Crude Oil Transportation segment, we recognize shipper deficiencies, or deferred revenue, for barrels committed by the customer to be transported in a month but not physically received by us for transport or delivered to the customers' agreed upon destination point. These shipper deficiencies are charged at the committed tariff rate per barrel and recorded as a contract liability until the barrels are physically transported and delivered, or when the likelihood that the customer will utilize the deficiency balance becomes remote. We also recognize contract liabilities, in the form of deferred revenue, under certain water business services contracts in the Gathering, Processing & Terminalling segment. Contract balances as of March 31, 2018 were as follows:

	March 31, 2018	January 1, 2018
	(in thousands)	
Accounts receivable from contracts with customers	$68,039	$61,888
Other accounts receivable	63,362	56,727
Accounts receivable, net	$131,401	$118,615
Deferred revenue from contracts with customers [1]	$99,922	$88,471

(1) Revenue recognized during the three months ended March 31, 2018 that was included in the deferred revenue balance at the beginning of the period was $3.1 million. This revenue primarily represented the utilization of shipper deficiencies at Pony Express.

12. Net Income per Limited Partner Unit

The Partnership's net income is allocated to the general partner and the limited partners in accordance with their respective ownership percentages, after giving effect to incentive distributions paid to the general partner.

We compute 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.

We calculate 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 our overall net income or other financial results; however, in periods in which aggregate net income exceeds our 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 our aggregate earnings, as if distributed, is allocated to the incentive distribution rights (which are currently held by our general partner), even though we make distributions on the basis of available cash and not earnings. In periods in which our aggregate net income does not exceed our 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.

The following table illustrates the calculation of net income per common unit for the three months ended March 31, 2018 and 2017:

	Three Months Ended March 31,	
	2018	2017
	(in thousands, except per unit amounts)	
Net income	$109,645	$71,784
Net income attributable to noncontrolling interests	(1,761)	(879)
Net income attributable to partners	107,884	70,905
General partner interest in net income	(41,032)	(30,583)
Net income available to common unitholders	$66,852	$40,322
Basic net income per common unit	$0.91	$0.56
Diluted net income per common unit	$0.91	$0.55
Basic average number of common units outstanding	73,200	72,544
Equity Participation Unit equivalent units	475	1,036
Diluted average number of common units outstanding	73,675	73,580

13. Regulatory Matters

There are no regulatory proceedings challenging the rates of Pony Express, Rockies Express, Tallgrass Interstate Gas Transmission, LLC ("TIGT") or Trailblazer Pipeline Company LLC ("Trailblazer"). We have made certain regulatory filings with the FERC, including the following:

Pony Express

On May 22, 2017 and May 31, 2017, Pony Express made tariff filings with the FERC in Docket Nos. IS17-263-000, IS17-464-000, and IS17-465-000 to increase the contract and non-contract rates by an amount reflecting the most recent FERC annual index adjustment of approximately 0.2%, which became effective July 1, 2017.

On November 30, 2017, Pony Express filed with the FERC in Docket No. IS18-60-000 certain changes to its tariffs to reflect the addition of two new destination points, which became effective January 1, 2018.

On December 29, 2017, Pony Express filed with the FERC in Docket No. IS18-113-000 certain changes to its tariffs to reflect a new origin point in Rooks County, Kansas, which became effective on February 1, 2018.

On February 28, 2018, Pony Express filed with the FERC in Docket No. IS18-199-000 certain changes to its tariffs to reflect a new origin point in Platteville, Colorado, which became effective on April 1, 2018.

On March 1, 2018, Pony Express submitted proposed revisions to its Rules and Regulations Tariff in Docket No. IS18-204-000 to establish the right to accept "Specialty Batches" of oil that do not conform to the Quality Specifications reflected in the tariff, provided that the acceptance is operationally feasible. These tariff changes became effective on April 1, 2018.

On April 11, 2018, Pony Express filed with the FERC in Docket No. IS18–267–000 certain changes to its tariffs to reflect additional contract rates from a new origin point in Platteville, Colorado, which are proposed to become effective on May 1, 2018.

Rockies Express

Rockies Express Zone 3 Capacity Enhancement Project – FERC Docket No. CP15-137-000

On March 31, 2015 in Docket No. CP15-137-000, Rockies Express filed with the FERC an application for authorization to construct and operate (1) three new mainline compressor stations located in Pickaway and Fayette Counties, Ohio and Decatur County, Indiana; (2) additional compressors at an existing compressor station in Muskingum County, Ohio; and (3) certain ancillary facilities. The facilities increased the Rockies Express Zone 3 east-to-west mainline capacity by 0.8 Bcf/d. Pursuant to the FERC's obligations under the National Environmental Policy Act, FERC staff issued an Environmental Assessment for the project on August 31, 2015. On February 25, 2016, the FERC issued a Certificate of Public Convenience and Necessity authorizing Rockies Express to proceed with the project. On March 14, 2016, Rockies Express commenced construction of the project facilities. The project was placed in-service for the full 0.8 Bcf/d on January 6, 2017.

Electric Power Charge Clarification - FERC Docket No. RP17-285

On December 21, 2016, in Docket No. RP17-285, Rockies Express proposed certain revisions to the General Terms and Conditions of its tariff to clarify that the electric power costs associated with the operation of gas coolers installed in association with the Zone 3 Capacity Enhancement Project at both electric and gas powered stations, will be included in the Power Cost Tracker. Several shippers submitted comments on the proposal. The FERC issued an order on January 19, 2017 accepting the proposed revisions permitting the recovery of electric power costs from the operation of both gas and electric powered compressor stations, subject to certain clarifications.

2017 Annual and Interim FERC Fuel Tracking Filings - FERC Docket Nos. RP17-401 and RP17-1064

On February 13, 2017, in Docket No. RP17-401, Rockies Express made its annual fuel and power cost tracker filing with a proposed effective date of April 1, 2017. The FERC issued an order accepting the filing, including certain requested waivers, on March 21, 2017. On September 20, 2017, Rockies Express made its interim fuel tracker filing in Docket No. RP17-1064 with a proposed effective date of November 1, 2017. The FERC issued an order accepting the filing on October 18, 2017.

Increased Frequency of FL&U and PCT Adjustments - FERC Docket No. RP18-228

On December 1, 2017, in Docket No. RP18-228, Rockies Express made a filing with the FERC to increase the frequency in which it may adjust fixed fuel and lost and unaccounted for retainages and power cost tracker charges during the year so that its recovery of fixed fuel and lost and unaccounted for charges and power costs more closely track usage. Rockies Express proposed an effective date of April 1, 2018. The comment period ended on December 13, 2017, and no parties opposed Rockies Express' filing. On April 4, 2018, the FERC issued a letter order accepting Rockies Express's proposal, subject to certain modifications. Rockies Express submitted a compliance filing reflecting the approved tariff provisions and requested modifications on April 10, 2018. No comments on the compliance filing were submitted by the comment deadline of April 16, 2018. On April 18, 2018, the FERC issued an order accepting Rockies Express's compliance filing effective April 19, 2018.

2018 Annual FERC Fuel Tracking Filing - FERC Docket No. RP18-453

On February 20, 2018, in Docket No. RP18-453, Rockies Express made its annual fuel and power cost tracker filing with a proposed effective date of April 1, 2018. The FERC issued an order accepting the filing on March 19, 2018.

Cheyenne Hub Enhancement Project - FERC Docket CP18-103

On March 2, 2018, Rockies Express submitted an application pursuant to section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of certain booster compressor units and ancillary facilities located at the Cheyenne Hub in Weld County, Colorado that will enable Rockies Express to provide a new hub service allowing for firm receipts and deliveries between Rockies Express and certain other interconnected pipelines at the Cheyenne Hub. Rockies Express filed this certificate application in conjunction with a concurrently filed certificate application by Cheyenne Connector, LLC ("Cheyenne Connector") for the Cheyenne Connector Pipeline Project further described below. The comment period for the Cheyenne Hub Enhancement Project closed on April 9, 2018. To date, various comments have been filed by market participants regarding the proposed project.

Cheyenne Connector

Cheyenne Connector Pipeline Project - FERC Docket CP18-102

On March 2, 2018, Cheyenne Connector, an indirect wholly-owned subsidiary of TEP, submitted an application pursuant to section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity to construct and operate a 70-mile 36 inch pipeline to transport natural gas from multiple gas processing plants in Weld County, Colorado to Rockies Express's Cheyenne Hub. The comment period for the Cheyenne Connector Pipeline Project closed on April 9, 2018. To date, various comments have been filed by market participants regarding the proposed project.

TIGT

General Rate Case Filing - FERC Docket No. RP16-137-000, et seq.

On October 30, 2015, in Docket No. RP16-137-000, et seq., TIGT filed a general rate case with the FERC pursuant to Section 4 of the National Gas Act ("NGA"). The general rate case was ultimately resolved via settlement, which the FERC approved on November 2, 2016, and a compliance filing that modernized TIGT's FERC Gas Tariff, consistent with prior FERC orders, which the FERC accepted on March 16, 2017. Per the terms of the settlement, TIGT is required to file a new general rate case on May 1, 2019 (provided that such rate case is not pre-empted by a pre-filing settlement).

2017 Annual Fuel Tracker Filing - FERC Docket No. RP17-428-000
On February 27, 2017, in Docket No. RP17-428-000, TIGT made its annual fuel tracker filing with a proposed effective date of April 1, 2017. The filing incorporated the FL&U tracker and power cost tracker mechanisms agreed to in the TIGT Rate Case Settlement. The FERC accepted the filing on March 21, 2017.
Electric Power Charge Clarification - FERC Docket No. RP17-1051-000
On September 15, 2017, in Docket No. RP17-1051-000, TIGT proposed certain revisions to its tariff to clarify, amongst other things, that the electric power costs associated with the operation of gas coolers at both electric and gas powered stations are properly included in the Power Cost Tracker. The FERC issued an order on October 3, 2017 accepting the proposed revisions.
2018 Annual Fuel Tracker Filing - FERC Docket No. RP18-533-000
On March 1, 2018, in Docket No. RP18-533-000, TIGT made its annual fuel tracker filing with a proposed effective date of April 1, 2018. The FERC accepted the filing on March 22, 2018.
Trailblazer
2017 Annual and Interim Fuel Tracker Filings - FERC Docket Nos. RP17-549-000 and RP17-1052-000
On March 22, 2017, in Docket No. RP17-549-000, Trailblazer made its annual fuel tracker filing with a proposed effective date of May 1, 2017. The FERC accepted the filing on April 19, 2017. On September 15, 2017, Trailblazer made its interim fuel tracker filing in Docket No. RP17-1052-000 with a proposed effective date of November 1, 2017. The FERC accepted the filing on October 13, 2017.
2018 Annual Fuel Tracker Filing - FERC Docket No. RP18-580-000
On March 22, 2018, in Docket No. in Docket No. RP18-580-000, Trailblazer made its annual fuel tracker filing with a proposed effective date of May 1, 2018. The FERC accepted the filing on April 20, 2018.
14. Legal and Environmental Matters
Legal
In addition to the matters discussed below, we are a defendant in various lawsuits arising from the day-to-day operations of our business. Although no assurance can be given, we believe, based on our experiences to date, that the ultimate resolution of such routine items will not have a material adverse impact on our business, financial position, results of operations, or cash flows.
We have evaluated claims in accordance with the accounting guidance for contingencies that we deem both probable and reasonably estimable and, accordingly, have recorded no reserve for legal claims as of March 31, 2018 or December 31, 2017.
Rockies Express
Ultra Resources
In early 2016, Ultra Resources, Inc. ("Ultra") defaulted on its firm transportation service agreement for approximately 0.2 Bcf/d through November 11, 2019. In late March 2016, Rockies Express terminated Ultra's service agreement. On April 14, 2016, Rockies Express filed a lawsuit against Ultra for breach of contract and damages in Harris County, Texas, seeking approximately $303 million in damages and other relief. On April 29, 2016, Ultra and certain of its debtor affiliates filed for protection under Chapter 11 of the United States Bankruptcy Code in United States Bankruptcy Court for the Southern District of Texas, which operated as a stay of the Harris County state court proceeding.
On January 12, 2017, Rockies Express and Ultra entered into an agreement to settle Rockies Express' approximately $303 million claim against Ultra. In accordance with the settlement agreement, Ultra made a cash payment to Rockies Express of $150 million on July 12, 2017, and entered into a new, seven-year firm transportation agreement with Rockies Express commencing December 1, 2019, for west-to-east service of 0.2 Bcf/d at a rate of approximately $0.37 per dth/d, or approximately $26.8 million annually. TEP received its proportionate distribution from the cash settlement payment in July 2017.

Environmental, Health and Safety

We are 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. We believe that compliance with these laws will not have a material adverse impact on our 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 us to incur significant costs. We had environmental reserves of $7.7 million at March 31, 2018 and December 31, 2017.

Rockies Express

Seneca Lateral

On January 31, 2018, Rockies Express experienced an operational disruption on its Seneca Lateral due to a pipe rupture and natural gas release in a rural area in Noble County, Ohio. There were no injuries reported and no evacuations. The release required Rockies Express to shut off the flow through the segment until February 27, 2018, when temporary repairs were completed allowing the segment to be placed back into service. Total cost of remediation is expected to be approximately $4.8 million prior to any insurance recoveries. A root cause investigation is ongoing.

TMID

Casper Plant, EPA Notice of Violation

In August 2011, the EPA and the Wyoming Department of Environmental Quality ("WDEQ") conducted an inspection of the Leak Detection and Repair ("LDAR") Program at the Casper Gas Plant in Wyoming. In September 2011, Tallgrass Midstream, LLC ("TMID") received a letter from the 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 EPA concerning settlement of this matter in April 2013 and received additional settlement communications from the EPA and Department of Justice beginning in July 2014. Settlement negotiations are continuing, including the expected inclusion of TIGT as a party to any possible settlement as a result of TIGT owning a compressor that is located adjacent to the Casper Gas Plant site.

Casper Gas Plant

On November 25, 2014, WDEQ issued a Notice of Violation for violations of Part 60 Subpart OOOO related to the Depropanizer project (wv-14388, issued 7/9/13) in Docket No. 5506-14. TMID had discussed the issues in a meeting with WDEQ in Cheyenne on November 17, 2014, and submitted a disclosure on November 20, 2014 detailing the regulatory issues and potential violations. The project triggered a modification of Subpart OOOO for the entire plant. The project equipment as well as plant equipment subjected to Subpart OOOO was not monitored timely, and initial notification was not made timely. Settlement negotiations with WDEQ are currently ongoing.

TMG

Archibald Booster Station

Tallgrass Midstream Gathering, LLC ("TMG") is currently a party to a remedy agreement entered into with the WDEQ in July 2013 with respect to the Archibald Booster Station located in Campbell County, Wyoming. In connection with the remedy agreement, TMG has agreed to complete certain remedial actions at the site related to a former earthen pit including semi-annual groundwater sampling, and quarterly recovery activities at monitoring wells. The facility is currently in compliance with the WDEQ under the remedy agreement.

Irwin Booster Station

TMG is also party to a remedy agreement entered into with the WDEQ in July 2013 with respect to the Irwin Booster Station located in Converse County, Wyoming. In connection with the remedy agreement, TMG has agreed to complete certain remedial actions at the site related to a former earthen pit including semi-annual groundwater sampling. The facility is currently in compliance with the WDEQ under the remedy agreement.

Trailblazer

Pipeline Integrity Management Program

Starting in 2014 Trailblazer's operating capacity was decreased as a result of smart tool surveys that identified approximately 25 - 35 miles of pipe as potentially requiring repair or replacement. During 2016 and 2017, Trailblazer incurred approximately $21.8 million of remediation costs to address this issue, including replacing approximately 8 miles of pipe. To date the pressure and capacity reduction has not prevented Trailblazer from fulfilling its firm service obligations at existing subscription levels or had a material adverse financial impact on us. However, Trailblazer intends to continue performing remediation to increase and maximize its operating capacity over the long-term and expects to spend in excess of $20 million during 2018 for this pipe replacement and remediation work. Trailblazer is exploring all possible cost recovery options to recover expenditures, including recovery through a general rate increase, negotiated rate agreements with its customers, or other FERC-approved recovery mechanisms.

In connection with our acquisition of Trailblazer in April 2014, TD agreed to indemnify TEP for certain out of pocket costs related to repairing or remediating the Trailblazer Pipeline. The contractual indemnity was capped at $20 million and subject to a $1.5 million deductible. TEP received the entirety of the $20 million from TD pursuant to the contractual indemnity as of December 31, 2017.

Pony Express

Pipeline Integrity

In connection with certain crack tool runs on the Pony Express System completed in 2015, 2016, and 2017, Pony Express completed approximately $18 million of remediation for anomalies identified on the Pony Express System associated with the initial conversion and commissioning of portions of the pipeline converted from natural gas to crude oil service. Remediation work is substantially complete as of March 31, 2018.

15. Reportable Segments

Our operations are located in the United States. We are organized into three reportable segments: (1) Natural Gas Transportation, (2) Crude Oil Transportation, and (3) Gathering, Processing & Terminalling.

Natural Gas Transportation

The Natural Gas Transportation segment is engaged in the ownership and operation of FERC-regulated interstate natural gas pipelines and an integrated natural gas storage facility that provide services to on-system customers (such as third-party LDCs), industrial users and other shippers. The Natural Gas Transportation segment includes our 49.99% membership interest in Rockies Express.

Crude Oil Transportation

The Crude Oil Transportation segment is engaged in the ownership and operation of the Pony Express System, which is a FERC-regulated crude oil pipeline serving the Bakken Shale, Denver-Julesburg and Powder River Basins, and other nearby oil producing basins. The Pony Express System also includes a lateral pipeline in Northeast Colorado, which interconnects with the Pony Express System just east of Sterling, Colorado, and an extension of the system from a new origin near Platteville, Colorado ending at the Buckingham Terminal.

Gathering, Processing & Terminalling

The Gathering, Processing & Terminalling segment is engaged in the ownership and operation of natural gas gathering and processing facilities that produce NGLs and residue gas sold in local wholesale markets or delivered into pipelines for transportation to additional end markets; our crude oil terminal services; water business services provided primarily to the oil and gas exploration and production industry; the transportation of NGLs; and Stanchion.

Corporate and Other

Corporate and Other includes corporate overhead costs that are not directly associated with the operations of our reportable segments, such as interest and fees associated with our revolving credit facility and the 2024 and 2028 Notes, public company costs, 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.

We consider Adjusted EBITDA our primary segment performance measure as we believe it is the most meaningful measure to assess our financial condition and results of operations as a public entity. We define Adjusted EBITDA, a non-GAAP measure, 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 our segment information for the periods indicated:

Revenue:	Three Months Ended March 31, 2018 Total Revenue	Inter-Segment	External Revenue	Three Months Ended March 31, 2017 Total Revenue	Inter-Segment	External Revenue
	(in thousands)					
Natural Gas Transportation	$36,202	$(1,858)	$34,344	$36,428	$(1,445)	$34,983
Crude Oil Transportation	89,966	(3,319)	86,647	84,994	—	84,994
Gathering, Processing & Terminalling	63,838	(5,735)	58,103	27,307	(2,884)	24,423
Corporate and Other	—	—	—	—	—	—
Total revenue	$190,006	$(10,912)	$179,094	$148,729	$(4,329)	$144,400

Adjusted EBITDA:	Three Months Ended March 31, 2018 Total Adjusted EBITDA	Inter-Segment	External Adjusted EBITDA	Three Months Ended March 31, 2017 Total Adjusted EBITDA	Inter-Segment	External Adjusted EBITDA
	(in thousands)					
Natural Gas Transportation	$90,519	$(2,255)	$88,264	$53,030	$(1,445)	$51,585
Crude Oil Transportation	59,456	4,150	63,606	55,491	4,228	59,719
Gathering, Processing & Terminalling	16,915	(1,895)	15,020	8,351	(2,783)	5,568
Corporate and Other	(1,853)	—	(1,853)	(1,761)	—	(1,761)
Reconciliation to Net Income:						
Add:						
Equity in earnings of unconsolidated investments			53,406			20,738
Non-cash gain related to derivative instruments, net of noncontrolling interests			2,674			2,441
Gain on disposal of assets			9,417			1,448
Less:						
Interest expense, net			(28,184)			(14,689)
Depreciation and amortization expense, net of noncontrolling interest			(25,854)			(21,867)
Distributions from unconsolidated investments			(65,857)			(30,819)
Non-cash compensation expense			(2,755)			(1,458)
Net income attributable to partners			$107,884			$70,905

Capital Expenditures:	Three Months Ended March 31, 2018	2017
	(in thousands)	
Natural Gas Transportation	$9,885	$4,655
Crude Oil Transportation	16,952	7,343
Gathering, Processing & Terminalling	31,139	14,771
Corporate and Other	784	—
Total capital expenditures	$58,760	$26,769

Assets:	March 31, 2018	December 31, 2017
	(in thousands)	
Natural Gas Transportation	$1,648,241	$1,606,666
Crude Oil Transportation	1,412,650	1,407,758
Gathering, Processing & Terminalling	1,095,410	943,340
Corporate and Other	34,578	19,589
Total assets	$4,190,879	$3,977,353

16. Subsequent Events

Pawnee Terminal

On January 2, 2018, Terminals entered into an agreement to acquire a 51% membership interest in the Pawnee, Colorado crude oil terminal ("Pawnee Terminal") from Zenith Energy Terminals Holdings, LLC for cash consideration of approximately $31 million. The transaction closed on April 1, 2018.

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

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 term our "general partner" refers to Tallgrass MLP GP, LLC. References to "TD" refer to Tallgrass Development, LP.

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the condensed consolidated financial statements and related notes thereto included elsewhere in this Quarterly Report. Additionally, the following discussion and analysis should be read in conjunction with our 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, 2017 (our "2017 Form 10-K") filed with the United States Securities and Exchange Commission (the "SEC") on February 13, 2018.

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," "estimate," "anticipate," "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 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. 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, including integrating the acquisitions discussed in Note 3 – Acquisitions and Dispositions;
- our ability to consummate the merger transaction with TEGP pursuant to the Merger Agreement discussed in Note 1 – Description of Business;
- the demand for our services, including crude oil transportation, storage, and terminalling services; natural gas transportation, storage, gathering and processing services; and water business services, as well as our ability to successfully contract or re-contract with our customers;
- large or multiple customer defaults, including defaults resulting from actual or potential insolvencies;
- our ability to successfully implement our business plan;
- changes in general economic conditions;
- competitive conditions in our industry;
- the effects of existing and future laws and governmental regulations;
- actions taken by governmental regulators of our assets, including the FERC;
- actions taken by third-party operators, processors and transporters;
- our ability to complete internal growth projects on time and on budget;

- the price and availability of debt and equity financing;

- the level of production of crude oil, natural gas and other hydrocarbons and the resultant market prices of crude oil, natural gas, natural gas liquids, and other hydrocarbons;
- the availability and price of natural gas and crude oil, and fuels 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, storing, and terminalling crude oil; transporting, storing, gathering and processing natural gas; and transporting, gathering and disposing of water produced in connection with hydrocarbon exploration and production activities;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- interest rates;
- labor relations;
- changes in tax laws, regulations and status;
- 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 in 2013 to own, operate, acquire and develop midstream energy assets in North America. Our operations are located in and provide services to certain key United States hydrocarbon basins, including the Denver-Julesburg, Powder River, Wind River, Permian and Hugoton-Anadarko Basins and the Niobrara, Mississippi Lime, Eagle Ford, Bakken, Marcellus, and Utica shale formations. We intend to continue to utilize the significant experience of our management team to execute our growth strategy of acquiring midstream assets, increasing utilization of our existing assets, and expanding our systems through construction of additional assets.

Our reportable business segments are:

- Natural Gas Transportation—the ownership and operation of FERC-regulated interstate natural gas pipelines and integrated natural gas storage facilities;
- Crude Oil Transportation—the ownership and operation of a FERC-regulated crude oil pipeline system; and
- Gathering, Processing & Terminalling—the ownership and operation of natural gas gathering and processing facilities; crude oil storage and terminalling facilities; the provision of water business services primarily to the oil and gas exploration and production industry; the transportation of NGLs; and the marketing of crude oil and NGLs.

Recent Developments

Distribution Announced

On March 26, 2018, the board of directors of our general partner declared a cash distribution for the quarter ended March 31, 2018 of $0.9750 per common unit. The distribution will be paid on May 15, 2018, to unitholders of record on April 30, 2018.

Pawnee Terminal

On January 2, 2018, Terminals entered into an agreement to acquire a 51% membership interest in the Pawnee Terminal from Zenith Energy Terminals Holdings, LLC for cash consideration of approximately $31 million. The transaction closed on April 1, 2018.

TEGP Merger Agreement

On March 26, 2018, we announced the execution of the Merger Agreement pursuant to which TEGP will acquire the approximately 47.6 million TEP common units held by the public in a share-for-unit merger transaction that is taxable for U.S. federal income tax purposes at a ratio of 2.0 TEGP Class A shares for each outstanding TEP common unit. As a result of the proposed transaction, our incentive distribution rights will be cancelled, our common units will no longer be publicly traded, and 100% of our equity interests will be owned by TEGP's subsidiary, Tallgrass Equity and its subsidiaries. Upon closing of the merger transaction, TEGP will change its name to Tallgrass Energy, LP ("Tallgrass Energy") and will trade on the New York Stock Exchange under the ticker symbol "TGE." Tallgrass Energy will continue to be taxed as a corporation for U.S. federal income tax purposes.

The Merger Agreement has been unanimously approved by the board of directors of TEGP's general partner, the conflicts committee of the board of directors of our general partner, and the board of directors of our general partner. Subject to customary approvals and conditions, including the approval by holders of a majority of the outstanding TEP common units, the merger is expected to close by the end of the second quarter of 2018.

In connection with the proposed transaction, TEGP filed with the SEC a registration statement on Form S-4 that included a preliminary proxy statement/prospectus for our unitholders. After the registration statement is declared effective, we will mail a definitive proxy statement/prospectus to our unitholders. The description of the proposed transaction above is not a substitute for the proxy statement/prospectus or registration statement or for any other document that TEGP or TEP may file with the SEC and send to TEGP’s and/or TEP’s shareholders or unitholders in connection with the proposed transaction. Investors and security holders of TEGP and TEP are urged to read the proxy statement/prospectus and other documents filed with the SEC carefully and in their entirety when they become available because they will contain important information. Investors and security holders will be able to obtain free copies of the proxy statement/prospectus and other documents filed with the SEC by TEGP or TEP through the website maintained by the SEC at http://www.sec.gov. Copies of the documents filed with the SEC by TEGP and TEP will be available free of charge on TEGP’s and TEP’s website at www.tallgrassenergylp.com, in the “Investor Relations” tab near the top of the page.

How We Evaluate Our Operations

We evaluate our results using, among other measures, contract profile 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 Profile and Volumes

Our results are driven primarily by the volume of natural gas transportation and storage capacity, crude oil transportation, storage, and terminalling capacity, NGL transportation capacity, and water transportation, gathering and disposal capacity under firm fee contracts, as well as the volume of natural gas that we gather and 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, cost of 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.

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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 generally 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 generally define as Adjusted EBITDA, plus deficiency payments received from or utilized by our customers, less cash interest costs, maintenance capital expenditures, distributions to noncontrolling interests in excess of earnings allocated to noncontrolling interests, and certain cash reserves permitted by our partnership agreement, to analyze our performance.

Maintenance capital expenditures are cash expenditures incurred (including expenditures for the construction or development of new capital assets) that we expect to maintain our long-term operating income or operating capacity. These expenditures typically include certain system integrity, compliance and safety improvements, and are presented net of noncontrolling interest and reimbursements. We collect deficiency payments for volumes committed by our customers to be transported in a month but not physically received for transport or delivered to the customers' agreed upon destination point. These deficiency payments are recorded as a deferred liability until the barrels are physically transported and delivered, or when the likelihood that the customer will utilize the deficiency balance becomes remote.

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 March 31,	
	2018	2017
	(in thousands)	
Reconciliation of Adjusted EBITDA to Net Income		
Net income attributable to partners	$107,884	$70,905
Add:		
Interest expense, net	28,184	14,689
Depreciation and amortization expense, net of noncontrolling interest	25,854	21,867
Distributions from unconsolidated investments	65,857	30,819
Non-cash compensation expense (1)	2,755	1,458
Less:		
Equity in earnings of unconsolidated investments	(53,406)	(20,738)
Gain on disposal of assets	(9,417)	(1,448)
Non-cash gain related to derivative instruments, net of noncontrolling interest	(2,674)	(2,441)
Adjusted EBITDA	$165,037	$115,111

Reconciliation of Adjusted EBITDA and Distributable Cash Flow to Net Cash Provided by Operating Activities		
Net cash provided by operating activities	$138,558	$104,241
Add:		
Interest expense, net	28,184	14,689
Other, including changes in operating working capital	(1,705)	(3,819)
Adjusted EBITDA	$165,037	$115,111
Add:		
Deficiency payments received, net	11,195	16,071
Less:		
Cash interest cost	(27,001)	(13,567)
Maintenance capital expenditures, net	(3,030)	(63)
Distributable Cash Flow	$146,201	$117,552

(1) Represents TEP's portion of non-cash compensation expense related to Equity Participation Units, excluding amounts allocated to TD prior to the merger of TD into Tallgrass Development Holdings, LLC, a wholly-owned subsidiary of Tallgrass Equity, on February 7, 2018.

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 March 31,	
	2018	2017
	(in thousands)	
Reconciliation of Adjusted EBITDA to Operating Income in the Natural Gas Transportation Segment [1]		
Operating income	$19,384	$18,168
Add:		
Depreciation and amortization expense	4,827	4,783
Distributions from unconsolidated investment	65,857	30,125
Other income, net	451	70
Less:		
Non-cash gain related to derivative instruments	—	(116)
Segment Adjusted EBITDA	$90,519	$53,030
Reconciliation of Adjusted EBITDA to Operating Income in the Crude Oil Transportation Segment [1]		
Operating income	$46,527	$43,725
Add:		
Depreciation and amortization expense, net of noncontrolling interest	13,279	13,287
Less:		
Adjusted EBITDA attributable to noncontrolling interests	(350)	(871)
Non-cash gain related to derivative instruments, net of noncontrolling interest	—	(650)
Segment Adjusted EBITDA	$59,456	$55,491
Reconciliation of Adjusted EBITDA to Operating Income in the Gathering, Processing & Terminalling Segment [1]		
Operating income	$23,305	$5,106
Add:		
Depreciation and amortization expense, net of noncontrolling interest	7,112	3,797
Non-cash (gain) loss related to derivative instruments	(2,674)	210
Distributions from unconsolidated investment	—	694
Less:		
Gain on disposal of assets	(9,417)	(1,448)

Adjusted EBITDA attributable to noncontrolling interests	(1,411)	(8)
Segment Adjusted EBITDA	$16,915	$8,351
Total Segment Adjusted EBITDA	$166,890	$116,872
Corporate general and administrative costs	(1,853)	(1,761)
Total Adjusted EBITDA	$165,037	$115,111

(1) Segment results as presented represent total operating income and Adjusted EBITDA, including intersegment activity, for the Natural Gas Transportation, Crude Oil Transportation, and Gathering, Processing & Terminalling segments. For reconciliations to the consolidated financial data, see Note 15 – Reportable Segments to the accompanying condensed consolidated financial statements.

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Results of Operations

The following provides a summary of our operating metrics for the periods indicated:

	Three Months Ended March 31,	
	2018	2017
Natural Gas Transportation Segment:		
Gas transportation average firm contracted volumes (MMcf/d) [(1)]	1,842	1,609
Crude Oil Transportation Segment:		
Crude oil transportation average contracted capacity (Bbls/d)	303,580	298,580
Crude oil transportation average throughput (Bbls/d)	289,739	261,904
Gathering, Processing & Terminalling Segment:		
Natural gas processing inlet volumes (MMcf/d)	117	103
Freshwater average volumes (Bbls/d)	45,512	64,754
Produced water gathering and disposal average volumes (Bbls/d)	85,406	9,760

(1) Volumes transported under firm fee contracts, excluding Rockies Express.

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

	Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Revenues:		
Crude oil transportation services	$84,738	$84,331
Natural gas transportation services	32,196	31,685
Sales of natural gas, NGLs, and crude oil	38,145	15,381
Processing and other revenues	24,015	13,003
Total Revenues	179,094	144,400
Operating Costs and Expenses:		
Cost of sales	26,351	12,370
Cost of transportation services	10,420	13,503
Operations and maintenance	16,399	12,903
Depreciation and amortization	26,123	21,403
General and administrative	16,367	13,663
Taxes, other than income taxes	8,879	8,226
Gain on disposal of assets	(9,417)	(1,448)
Total Operating Costs and Expenses	95,122	80,620
Operating Income	83,972	63,780
Other Income (Expense):		
Equity in earnings of unconsolidated investments	53,406	20,738
Interest expense, net	(28,184)	(14,689)
Other income, net	451	1,955
Total Other Income (Expense)	25,673	8,004
Net income	109,645	71,784
Net income attributable to noncontrolling interests	(1,761)	(879)
Net income attributable to partners	$107,884	$70,905
Other Financial Data:		
Adjusted EBITDA [(1)]	$165,037	$115,111

(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 March 31, 2018 Compared to the Three Months Ended March 31, 2017

Revenues. Total revenues were $179.1 million for the three months ended March 31, 2018, compared to $144.4 million for the three months ended March 31, 2017, which represents an increase of $34.7 million, or 24%, in total revenues. The overall increase in revenue was largely driven by increased revenues of $36.5 million and $5.0 million in the Gathering, Processing & Terminalling and the Crude Oil Transportation segment, respectively, as discussed further below, partially offset by a $6.6 million increase in eliminations of intersegment revenue.

Operating costs and expenses. Operating costs and expenses were $95.1 million for the three months ended March 31, 2018 compared to $80.6 million for the three months ended March 31, 2017, which represents an increase of $14.5 million, or 18%. The overall increase in operating costs and expenses is driven by increased operating costs and expenses of $18.3 million and $2.2 million in the Gathering, Processing & Terminalling and Crude Oil Transportation segments, respectively, partially offset by decreased operating costs and expenses of $4.6 million and $1.4 million in the Corporate and Other and Natural Gas Transportation segments, as discussed further below. The decrease in Corporate and Other expenses was primarily driven by a $6.6 million increase in eliminations of intersegment operating costs and expenses, partially offset by a $1.4 million increase in corporate general and administrative costs primarily due to equity-based compensation grants issued during the year ended December 31, 2017 under the general partner's Long-term Incentive Plan and costs associated with the TEGP Merger Agreement, as well as a $0.6 million increase in depreciation and amortization costs due to the administrative assets acquired from TD in February 2018.
Equity in earnings of unconsolidated investments. Equity in earnings of unconsolidated investments was $53.4 million and $20.7 million for the three months ended March 31, 2018 and 2017, respectively. Equity in earnings of unconsolidated investments of $53.4 million for three months ended March 31, 2018 primarily reflects our portion of earnings and the $6.6 million of amortization of a negative basis difference associated with our 49.99% membership interest in Rockies Express as well as $1.3 million of equity in earnings related to our 63% membership interest in BNN Colorado Water, LLC ("BNN Colorado"). Equity in earnings of unconsolidated investments of $20.7 million for the three months ended March 31, 2017 primarily reflects our portion of earnings and the $3.5 million of amortization of a negative basis difference associated with our 25% membership interest in Rockies Express, as well as $0.7 million of equity in earnings related to our 20% membership interest in Deeprock Development.
Interest expense, net. Interest expense of $28.2 million for the three months ended March 31, 2018 was primarily composed of interest and fees associated with our revolving credit facility, the 2024 Notes issued on September 1, 2016 and May 16, 2017, and the 2028 Notes issued on September 15, 2017 and December 11, 2017. Interest expense of $14.7 million for the three months ended March 31, 2017 was primarily composed of interest and fees associated with our revolving credit facility and the 2024 Notes issued on September 1, 2016. The increase in interest and fees is primarily due to increased borrowings to fund a portion of our 2017 and 2018 acquisitions, as well as the higher borrowing rate on the 2024 and 2028 Notes, the proceeds of which were used to repay borrowings under our revolving credit facility.
Other income, net. Other income, net typically includes rental income and income earned from certain customers related to the capital costs we incurred to connect these customers to our system. Other income for the three months ended March 31, 2018 was $0.5 million compared to $2.0 million for the three months ended March 31, 2017. Other income of $2.0 million for the three months ended March 31, 2017 included a $1.9 million unrealized gain on derivative instrument related to the change in fair value of the call option received from TD as part of the acquisition of an additional 31.3% membership interest in Pony Express as discussed further in Note 8 – Risk Management.
Net income attributable to noncontrolling interests. Net income attributable to noncontrolling interests of $1.8 million for the three months ended March 31, 2018, primarily reflects the net income allocated to the 40% noncontrolling interest in Deeprock Development, as well as $0.3 million allocated to the 2% noncontrolling interest in Pony Express prior to our acquisition of the 2% membership interest on February 1, 2018. Net income attributable to noncontrolling interests of $0.9 million for the three months ended March 31, 2017, primarily reflects the net income allocated to the 2% noncontrolling interest in Pony Express.

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

Segment Financial Data - Natural Gas Transportation [1]	Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Revenues:		
Natural gas transportation services	$34,054	$33,130
Sales of natural gas, NGLs, and crude oil	237	1,651
Processing and other revenues	1,911	1,647
Total revenues	36,202	36,428
Operating costs and expenses:		
Cost of sales	343	1,070
Cost of transportation services	132	760
Operations and maintenance	6,163	6,478
Depreciation and amortization	4,827	4,783
General and administrative	3,934	3,794
Taxes, other than income taxes	1,419	1,375
Total operating costs and expenses	16,818	18,260
Operating income	$19,384	$18,168

(1) Segment results as presented represent total revenue and operating income, including intersegment activity. For reconciliations to the consolidated financial data, see Note 15 – Reportable Segments to the accompanying condensed consolidated financial statements.

Three Months Ended March 31, 2018 Compared to the Three Months Ended March 31, 2017

Revenues. Natural Gas Transportation segment revenues were $36.2 million for the three months ended March 31, 2018, compared to $36.4 million for the three months ended March 31, 2017, which represents a decrease of $0.2 million, or 1%, in segment revenues due to a $1.4 million decrease in sales of natural gas driven by decreased volumes sold, partially offset by a $0.9 million increase in natural gas transportation services due to colder weather in the first quarter of 2018, resulting in higher volumes transported during the three months ended March 31, 2018, and a $0.3 million increase in other revenue.

Operating costs and expenses. Operating costs and expenses in the Natural Gas Transportation segment were $16.8 million for the three months ended March 31, 2018, compared to $18.3 million for the three months ended March 31, 2017, which represents a decrease of $1.4 million, or 8%. The overall decrease in operating costs and expenses was primarily due to a $0.7 million decrease in cost of sales driven by decreased volumes of natural gas sold and a $0.6 million decrease in the cost of transportation services driven by valuation adjustments on fuel tracker liabilities.

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

Segment Financial Data - Crude Oil Transportation [1]	Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Revenues:		
Crude oil transportation services	$88,057	$84,331
Sales of natural gas, NGLs, and crude oil	1,909	663
Total revenues	89,966	84,994
Operating costs and expenses:		
Cost of sales	1,966	—
Cost of transportation services	14,387	13,882
Operations and maintenance	2,870	2,878
Depreciation and amortization	13,366	13,015
General and administrative	4,492	5,194
Taxes, other than income taxes	6,358	6,300
Total operating costs and expenses	43,439	41,269
Operating income	$46,527	$43,725

(1) Segment results as presented represent total revenue and operating income, including intersegment activity. For reconciliations to the consolidated financial data, see Note 15 – Reportable Segments to the accompanying condensed consolidated financial statements.

Three Months Ended March 31, 2018 Compared to the Three Months Ended March 31, 2017

Revenues. Crude Oil Transportation segment revenues were $90.0 million for the three months ended March 31, 2018, compared to $85.0 million for the three months ended March 31, 2017, which represents an increase of $5.0 million, or 6%, in segment revenues driven by a $3.7 million increase in crude oil transportation services and a $1.2 million increase in sales of crude oil primarily due to increased volumes sold during the three months ended March 31, 2018. The increase in crude oil transportation revenue was primarily driven by a $4.3 million increase in committed volume shipments that were deficient during the three months ended March 31, 2017 and a $3.7 million increase in walk-up barrels shipped during the three months ended March 31, 2018 compared to the three months ended March 31, 2017. These increases were partially offset by a $4.5 million net decrease in revenue from a committed shipper that extended its contract during the fourth quarter of 2017, thereby paying a lower tariff rate, which was partially offset by increased volumes shipped.

Operating costs and expenses. Operating costs and expenses in the Crude Oil Transportation segment were $43.4 million for the three months ended March 31, 2018 compared to $41.3 million for the three months ended March 31, 2017, which represents an increase of $2.2 million, or 5%. The overall increase in operating costs and expenses was primarily driven by a $2.0 million increase in cost of sales driven by increased volumes sold and a $0.5 million increase in cost of transportation services, partially offset by a $0.7 million decrease in general and administrative expenses.

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

Segment Financial Data - Gathering, Processing & Terminalling [1]	Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Revenues:		
Sales of natural gas, NGLs, and crude oil	$35,999	$13,067
Processing and other revenues	27,839	14,240
Total revenues	63,838	27,307
Operating costs and expenses:		
Cost of sales	24,566	11,401
Cost of transportation services	6,289	3,089
Operations and maintenance	7,366	3,547
Depreciation and amortization	7,294	3,605
General and administrative	3,333	1,456
Taxes, other than income taxes	1,102	551
Gain on disposal of assets	(9,417)	(1,448)
Total operating costs and expenses	40,533	22,201
Operating income (loss)	$23,305	$5,106

(1) Segment results as presented represent total revenue and operating income, including intersegment activity. For reconciliations to the consolidated financial data, see Note 15 – Reportable Segments to the accompanying condensed consolidated financial statements.

Three Months Ended March 31, 2018 Compared to the Three Months Ended March 31, 2017

Revenues. Gathering, Processing & Terminalling segment revenues were $63.8 million for the three months ended March 31, 2018, compared to $27.3 million for the three months ended March 31, 2017, which represents a $36.5 million, or 134%, increase in segment revenues. The increase in segment revenues was primarily due to a $22.9 million increase in sales of natural gas, NGLs, and crude oil and a $13.6 million increase in processing and other revenues. The increase in sales of natural gas, NGLs, and crude oil was driven by (i) increased sales of NGLs of $10.3 million primarily due to higher throughput volumes and increased volumes sold driven by the Douglas Gathering System acquisition in June 2017, (ii) increased sales of natural gas of $7.9 million due to sales of residue gas from the Douglas Gathering System, and (iii) crude oil sales of $4.5 million at Stanchion during the first quarter of 2018. The increase in processing and other revenues was driven by (i) increased water business services revenue of $6.3 million driven by the acquisition of BNN North Dakota in January 2018 and increased produced water disposal volumes; (ii) increased terminal services revenue of $5.5 million driven by the acquisition of Deeprock North in January 2018 and the acquisition of a controlling interest in and subsequent consolidation of Deeprock Development in July 2017; and (iii) increased processing fee income of $1.6 million primarily driven by changes in the accounting treatment of certain commodities retained as consideration for processing services to processing fee revenue beginning January 1, 2018 as discussed further in Note 11 – Revenue from Contracts with Customers.

Operating costs and expenses. Operating costs and expenses in the Gathering, Processing & Terminalling segment were $40.5 million for the three months ended March 31, 2018 compared to $22.2 million for the three months ended March 31, 2017, which represents an increase of $18.3 million, or 83%. The increase in operating costs and expenses was primarily driven by (i) a $13.2 million increase in cost of sales primarily driven by higher producer settlements and higher NGL sales attributable to the acquisition of the Douglas Gathering System as discussed above, (ii) increases of $3.8 million, $3.7 million, and $1.9 million in operations and maintenance costs, depreciation and amortization, and general and administrative costs, respectively, all primarily driven by the 2018 acquisitions of BNN North Dakota and Deeprock North and the 2017 acquisitions of the Douglas Gathering System and Deeprock Development, and (iii) an increase of $3.2 million in cost of transportation services due to crude oil transportation fees paid by Stanchion during the three months ended March 31, 2018. The increase in operating costs and expenses was partially offset by the $9.4 million gain on the disposal of TCG during the three months ended March 31, 2018, compared to the $1.4 million gain on disposal of assets during the three months ended March 31, 2017.

Liquidity and Capital Resources Overview

Our primary sources of liquidity for the three months ended March 31, 2018 were 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 equity and/or debt securities.

We believe that cash on hand, cash generated from operations, and availability under our revolving credit facility will be adequate to meet our operating needs, our planned short-term maintenance 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 revolving credit facility and issuances of debt and/or equity securities. If the merger transaction contemplated by the Merger Agreement is consummated, our common units will no longer be publicly traded, and as a result, we would not expect issuances of additional equity securities at TEP to provide a source of liquidity following the closing of the merger transaction. For additional information regarding our revolving credit facility and senior unsecured notes, see Note 9 – Long-term Debt. For additional information regarding our equity transactions, see Note 10 – Partnership Equity and Distributions.

Our total liquidity as of March 31, 2018 and December 31, 2017 was as follows:

	March 31, 2018	December 31, 2017
	(in thousands)	
Cash on hand	$4,065	$1,809
Total capacity under the revolving credit facility	1,750,000	1,750,000
Less: Outstanding borrowings under the revolving credit facility	(816,000)	(661,000)
Less: Letters of credit issued under the revolving credit facility	(94)	(94)
Available capacity under the revolving credit facility	933,906	1,088,906
Total liquidity	$937,971	$1,090,715

Working Capital

Working capital is the amount by which current assets exceed current liabilities. While various other factors may impact our working capital requirements from period to period, our working capital requirements have typically been, and we expect will continue to be, driven by changes in accounts receivable, accounts payable and deferred revenue. We manage our working capital needs through borrowings and repayments of borrowings under our revolving credit facility. Factors impacting changes in accounts receivable and accounts payable could include the timing of collections from customers, payments to suppliers, and the level of spending for capital expenditures. Changes in the market prices of energy commodities that we buy and sell in the normal course of business can also impact the timing of changes in accounts receivable and accounts payable. Factors impacting deferred revenue include the volume of barrels transported, the amount of deficiency payments received, and the volume of prior deficiencies utilized during the period.

As of March 31, 2018, we had a working capital deficit of $106.3 million compared to a working capital deficit of $102.4 million at December 31, 2017, which represents an increase in the working capital deficit of $3.9 million. The overall increase in the working capital deficit was primarily attributable to changes in the following components:

- an increase in accounts payable of $21.1 million primarily due to crude oil purchases at Stanchion; and
- an increase in deferred revenue of $11.5 million primarily from deficiency payments collected by Pony Express and deferred revenue at BNN North Dakota, acquired in January 2018.

These working capital decreases were partially offset by:

- an increase in accounts receivable of $12.8 million primarily due to the BNN North Dakota acquisition in January 2018, as well as crude oil sales at Stanchion;
- an increase in inventories of $10.5 million due to the purchase of line fill at Stanchion; and
- a decrease in accounts payable of $5.4 million to related parties, as payroll and other administrative activity was moved to TEP from TD during the first quarter of 2018.

A material adverse change in operations, available financing under our revolving credit facility, or available financing from the equity or debt capital markets 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:

	Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Net cash provided by (used in):		
Operating activities	$138,558	$104,241
Investing activities	$(129,037)	$(562,042)
Financing activities	$(7,265)	$457,126

Three Months Ended March 31, 2018 Compared to the Three Months Ended March 31, 2017

Operating Activities. Cash flows provided by operating activities were $138.6 million and $104.2 million for the three months ended March 31, 2018 and 2017, respectively. The increase in net cash flows provided by operating activities of $34.3 million was primarily driven by a $31.3 million increase in distributions received from Rockies Express as a result of our increased membership interest effective March 31, 2017.

Investing Activities. Cash flows used in investing activities were $129.0 million for the three months ended March 31, 2018, primarily driven by:

- cash outflows of $95.0 million for the acquisition of BNN North Dakota;
- capital expenditures of $58.8 million, primarily due to spending on a 55-mile extension on the Pony Express system, construction of the Buckingham Terminal expansion, a new 70-mile natural gas pipeline located in Colorado ("Cheyenne Connector"), additional water gathering infrastructure located in North Dakota, and construction of the Grasslands and Natoma Terminals; and
- cash outflows of $19.5 million for the acquisition of a 38% membership interest in Deeprock North.

These cash outflows were partially offset by cash inflows of:

- $50.0 million from the sale of TCG; and
- $13.8 million of distributions received from Rockies Express in excess of cumulative earnings recognized.

Cash flows used in investing activities were $562.0 million for the three months ended March 31, 2017, primarily driven by:

- cash outflows of $400.0 million for the acquisition of an additional 24.99% membership interest in Rockies Express;
- cash outflows of $140.0 million for the acquisition of Terminals and NatGas; and
- capital expenditures of $26.8 million, primarily due to spending on an additional freshwater connection at Water Solutions and remediation digs on the Pony Express System as discussed in Note 14 – Legal and Environmental Matters.

These cash outflows were partially offset by $10.1 million of distributions from Rockies Express in excess of cumulative earnings recognized.

Financing Activities. Cash flows used in financing activities were $7.3 million for the three months ended March 31, 2018, primarily driven by:

- distributions to unitholders of $111.0 million; and
- cash outflows of $50.0 million for the acquisition of an additional 2% membership interest in Pony Express.

These financing cash outflows were partially offset by $155.0 million of net borrowings under the revolving credit facility.

Cash flows provided by financing activities were $457.1 million for the three months ended March 31, 2017, primarily driven by:

- net borrowings under the revolving credit facility of $552.0 million; and
- net cash proceeds of $99.4 million from the issuance of 2,087,647 common units under the Equity Distribution Agreements.

These financing cash inflows were partially offset by cash outflows of:

- distributions to unitholders of $88.2 million;
- $72.4 million for the partial exercise of the call option granted by TD covering 1,703,094 common units; and
- $35.3 million for the 736,262 common units repurchased from TD.

Distributions

We do not have a legal obligation to pay distributions except as provided in our partnership agreement. A distribution of $0.9750 per unit, or $112.5 million in the aggregate, for the three months ended March 31, 2018 was announced on March 26, 2018 and will be paid on May 15, 2018 to unitholders of record on April 30, 2018. As of May 3, 2018, we had a total of 74,034,144 common and general partner units outstanding, which equates to an aggregate minimum distribution of approximately $21.3 million per quarter and approximately $85.1 million per year. We intend to continue to pay quarterly distributions at or above the amount of the minimum quarterly distribution, which is $0.2875 per unit.

Capital Requirements

The midstream energy business can be capital-intensive, requiring significant investment to maintain and upgrade existing operations. Our capital requirements have consisted primarily of, and we anticipate will continue to consist of, the following:

- maintenance capital expenditures, which are cash expenditures incurred (including expenditures for the construction or development of new capital assets) that we expect to maintain our long-term operating income or operating capacity. These expenditures typically include certain system integrity, compliance and safety improvements; and
- expansion capital expenditures, which are cash expenditures we expect will increase our operating income or operating capacity over the long-term. Expansion capital expenditures include acquisitions or capital improvements (such as additions to or improvements on the capital assets owned, or acquisition or construction of new capital assets).

We expect to incur approximately $326 million for expansion capital projects and approximately $24 million for maintenance capital expenditures in 2018.

The determination of capital expenditures as maintenance or expansion is made at the individual asset level during our budgeting process and as we approve, execute, and monitor our capital spending. The following table summarizes the maintenance and expansion capital expenditures incurred at our consolidated entities:

	Three Months Ended March 31,	
	2018	2017
	(in thousands)	
Maintenance capital expenditures	$3,030	$63
Expansion capital expenditures	57,067	22,420
Total capital expenditures incurred	$60,097	$22,483

Capital expenditures incurred represent capital expenditures paid and accrued during the period. Capital expenditures are presented net of noncontrolling interest, and contributions and reimbursements received. The increase in maintenance capital expenditures to $3.0 million for the three months ended March 31, 2018 from $0.1 million for the three months ended March 31, 2017 is primarily driven by contributions from TD to TEP in order to indemnify TEP for certain out of pocket costs related to repairing or remediating the Trailblazer Pipeline during the three months ended March 31, 2017, as discussed further in Note 14 – Legal and Environmental Matters. Maintenance capital expenditures on our assets occur on a regular schedule, but most major maintenance projects are not required every year so the level of maintenance capital expenditures naturally varies from year to year and from quarter to quarter. Expansion capital expenditures were $57.1 million for the three months ended March 31, 2018 compared to $22.4 million for the three months ended March 31, 2017. Expansion capital expenditures for the three months ended March 31, 2018 consisted primarily of spending on a 55-mile extension on the Pony Express system, construction of the Buckingham Terminal expansion, the Cheyenne Connector, additional water gathering infrastructure located in North Dakota, and construction of the Grasslands Terminal and the Natoma Terminal. Expansion capital expenditures of $22.4 million for the three months ended March 31, 2017 consisted primarily of spending on an additional freshwater connection at Water Solutions and remediation digs on the Pony Express System, as discussed in Note 14 – Legal and Environmental Matters.

During the three months ended March 31, 2018, we made an initial contribution of $3.5 million to Iron Horse, a newly formed unconsolidated affiliate. In connection with our 75% membership interest in Iron Horse, we have made commitments to fund our proportionate share of the remaining cost to construct the pipeline, estimated at $98.5 million as of March 31, 2018. In addition, we invested cash in unconsolidated affiliates, including Rockies Express and BNN Colorado of $7.2 million and $6.7 million during the three months ended March 31, 2018 and 2017, respectively, to fund our share of capital projects. We have also committed to Rockies Express to fund the repayment of Rockies Express' $550 million 6.85% senior notes due July 15, 2018, in proportion to our 49.99% membership interest, which we intend to fund through borrowings under our revolving credit facility.

We intend to make cash distributions to our unitholders and our general partner. Due to our cash distribution policy, we expect that we will distribute to our unitholders most of the cash generated by our operations. We expect to fund future capital expenditures with funds generated from our operations, borrowings under our revolving credit facility, the issuance of additional partnership units and/or the issuance of long-term debt. If these sources are not sufficient, we may reduce our discretionary spending.

Contractual Obligations

There have been no material changes in our contractual obligations as reported in our 2017 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 2017 Form 10-K for the year ended December 31, 2017 and have not changed, with the exception of the following addition related to our implementation of the guidance in ASC Topic 606, Revenue from Contracts with Customers, as discussed in Note 2 – Summary of Significant Accounting Policies.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Revenue Recognition		
The majority of our revenue is derived from long-term contracts that can span several years. Accounting for long-term contracts involves the use of various techniques to estimate total contract revenue and determine the timing of revenue recognition. We periodically evaluate our estimates with respect to the probability of our customers	We review our deferred revenue (contract liabilities) at each balance sheet date to determine the probability that our customers will exercise their remaining rights. We recognize revenue when the probability becomes remote that the customer will exercise its remaining rights. Our evaluation	If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, the timing of our revenue recognition with respect to deferred revenue

exercising their rights and recognize revenue associated with contract liabilities when the probability becomes remote that the customer will exercise its remaining rights.	requires management to apply judgment in estimating future system capacity and the ability of our customers to utilize that capacity.	could be impacted and we may experience material changes in revenue.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Historically, we have had a limited amount of direct commodity price exposure related to natural gas collected for electrical compression costs at TIGT, natural gas used at TMID and crude oil collected as part of our contractual pipeline loss allowance at Pony Express and Terminals. Accordingly, we have historically entered into derivative contracts with third parties for all or a portion of these volumes for the purpose of hedging our commodity price exposures. In addition, Stanchion transacts in crude oil and enters into physical and financial derivative contracts in connection with these transactions.

The majority of TMID's Adjusted EBITDA comes from volumetric fee or commodity sensitive contracts. The profitability of our commodity sensitive processing contracts that include keep whole or percent of proceeds components is affected by volatility in prevailing NGL and natural gas prices. During the three months ended March 31, 2018, TMID represented 5% of our consolidated Adjusted EBITDA.

We measure the risk of price changes in our crude oil and natural gas derivatives 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 primarily 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 commodity prices.

The following table summarizes our commodity derivatives and the change in fair value that would be expected from a 10% price increase or decrease as of March 31, 2018, assuming a parallel shift in the forward curve through the end of 2018:

	Fair Value	Effect of 10% Price Increase	Effect of 10% Price Decrease
	(in thousands)		
Crude oil derivative contracts [(1)]	$306	$(1,525)	$ 1,525

(1) Represents the forward sale of 242,000 barrels of crude oil in our Gathering, Processing & Terminalling segment which will settle throughout the second quarter of 2018.

Interest Rate Risk

As of March 31, 2018, we have issued $750 million of 2024 Notes and $750 million of 2028 Notes. In addition, we have a $1.75 billion revolving credit facility with borrowings of $816.0 million. Borrowings under the revolving 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. The applicable margin ranges from 0.50% to 1.50% for base rate borrowings and 1.50% to 2.50% for reserve adjusted Eurodollar rate borrowings, based upon our total leverage ratio.

We do not currently hedge the interest rate risk on our borrowings under the revolving 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 $0.3 million based on our outstanding debt under our revolving credit facility as of March 31, 2018.

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.

A substantial majority of our revenue is produced under long-term firm fee contracts with high-quality customers. The customer base we currently serve under these contracts generally has a strong credit profile, with a majority of our revenues derived from customers who have BBB- or Baa3 and better credit ratings or are part of corporate families with such credit ratings as of March 31, 2018.

We also have indirect credit risk exposure with respect to our investment in Rockies Express. See Item 1A.—Risk Factors in our 2017 Form 10-K for additional information.

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

During the first quarter of 2018, we completed the conversion to a new contract and volume management system used by TMID to support the Douglas Gathering System which was acquired in 2017. This system was utilized to produce financial information contained in this Quarterly Report. There have been no other 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 March 31, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings

See Note 14 – Legal and Environmental Matters to the condensed consolidated financial statements included in Part I—Item 1.—Financial Statements of this Quarterly Report, which is incorporated herein by reference.

Item 1A. Risk Factors

Item 1A of our 2017 Form 10-K 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 March 31, 2018. There have been no material changes to the risk factors contained in our 2017 Form 10-K.

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

None.

Item 6. Exhibits

Exhibit No.	Description
2.1	Agreement and Plan of Merger, dated as of March 26, 2018, by and among Tallgrass Energy GP, LP, Tallgrass Equity, LLC, Razor Merger Sub, LLC, Tallgrass Energy Partners, LP and Tallgrass MLP GP, LLC (incorporated by reference to Exhibit 2.1 to Tallgrass Energy Partners, LP's Current Report on Form 8-K filed on March 27, 2018).
10.1	Support Agreement, dated as of March 26, 2018, by and among Tallgrass Energy GP, LP, Tallgrass Equity, LLC and Tallgrass Energy Partners, LP (incorporated by reference to Exhibit 10.1 to Tallgrass Energy Partners, LP's Current Report on Form 8-K filed on March 27, 2018).
10.2	Second Amended and Restated Credit Agreement, dated June 2, 2017, by and among Tallgrass Energy Partners, LP, Wells Fargo Bank, National Association, as administrative agent, and a syndicate of lenders named therein (incorporated by reference to Exhibit 10.1 to Tallgrass Energy Partners, LP's Quarterly Report on Form 10-Q filed on August 2, 2017).
12.1*	Computation of Ratio of Earnings to Fixed Charges
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

SIGNATURES

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:	May 3, 2018	By:	/s/ Gary J. Brauchle	
			Name:	Gary J. Brauchle
			Title:	Executive Vice President and Chief Financial Officer (Duly Authorized Officer and Principal Financial Officer)

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