



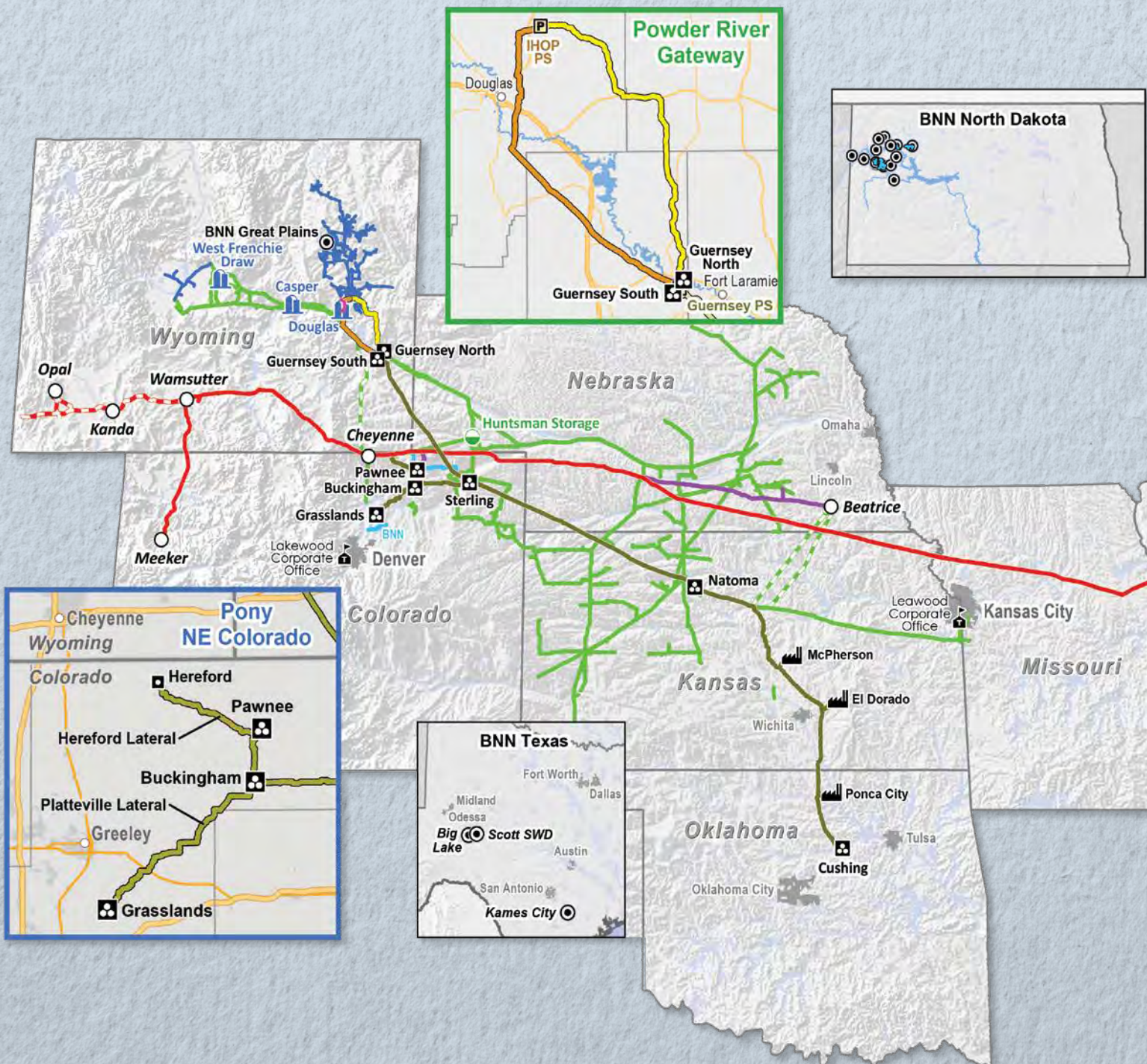
2 0 1 9 A N N U A L R E P O R T



TALLGRASS
ENERGY

Critical Infrastructure.

We're a midstream infrastructure company, transporting crude oil and natural gas from some of the nation's most prolific basins in the Rocky Mountains, Upper Midwest and Appalachian regions with access to major demand markets in the Rockies, the Midwest, eastern Ohio and points in between. Since our inception, we've built a strong portfolio of integrated transportation, storage, terminal, water management, gathering, processing and treating assets to support our customers, increase value and deliver outstanding long-term returns for our investors.



BNN CES Ohio

In 2019, we acquired Central Environmental Services, a water disposal provider serving E&P companies in the Marcellus and Utica. With that acquisition, BNN is an industry-leading water services provider serving seven North American shale basins. Through BNN Appalachia Water Infrastructure Network, BNN is developing a produced water infrastructure network to support producers in the Marcellus and Utica. The pipeline is strategically located and offers significant logistical efficiencies over existing truck routes. By reducing truck traffic, and optimizing water recycling options, the BNN system is more environmentally friendly, improves road safety and minimizes road damage.

Pony Express Expansion

We continued to optimize the Pony Express system by connecting more volumes in the D-J and Powder River basins. The Hereford Lateral extended Pony's reach deep into the D-J in northern Weld County, Colo., and from Hereford, PXP is extending to Carpenter in Wyoming in 2020. We placed the Platteville Extension in service, along with the associated Grasslands Terminal, nearly doubling the capacity of the Platteville Extension with available horsepower.

Powder River Gateway

We closed the expansion of our joint venture with Silver Creek Midstream, which operates the Powder River Gateway system in the heart of the Powder River Basin. Tallgrass owns 51 percent of and operates the JV, which consists of the Powder River Express Pipeline, Iron Horse Pipeline and the terminal assets at Guernsey, Wyo. The Powder River Basin is an important growth area and a strategic supply point for our crude oil businesses.

54%

Natural Gas Transportation

34%

Crude Oil Transportation

12%

G&P and Terminalling

Note: Represents Adjusted EBITDA by segment for 2019.

TALLGRASS SYSTEM MAP

Crude Oil

-  Pony Express Pipeline
-  Iron Horse Pipeline
-  Powder River Express Pipeline
-  Oil Terminal
-  Connected Third Party Refinery

Natural Gas

-  Rockies Express Pipeline
-  Lease of Overthrust Pipeline Capacity
-  Tallgrass Interstate Gas Transmission
-  TIGT Off System Transport Capacity
-  TIGT Gas Storage Field
-  Trailblazer Pipeline Company

Gathering and Processing

-  Tallgrass Midstream Facilities
-  Tallgrass Midstream Gathering

Natural Gas Liquids

-  TMID NGL Pipeline

Water

-  BNN Water Solutions





LETTER TO TGE SHAREHOLDERS

2019 was an eventful year—one that perhaps set the stage for transformational change at Tallgrass Energy. As part of that change, I'm penning my first letter to shareholders as the company's new CEO. I'm sincerely humbled as I consider the significance of that. It has been my privilege to be associated with these assets and this team for nearly 12 years, including my time with the assets under prior management. Time and again, Tallgrass employees have come together as a team to create and execute winning business strategies. I am eager to build on this strong track record and guide the way to an even more promising future.

Before I look back at our commercial and operational accomplishments in 2019, I want to take a moment to acknowledge the strong legacy David Dehaemers left behind when he retired as CEO late last year. Under Dave's leadership, Tallgrass grew into an amazing cache of energy infrastructure assets that will serve the country for years to come.

In January 2019, Blackstone Infrastructure Partners and its affiliates agreed to purchase TGE's general partner and an approximately 44 percent economic interest in Tallgrass. That transaction closed in March, and we gained what we view as an ideal partner in Blackstone. Their scale, access to substantial long-term capital, and investment expertise across our industry will be extremely beneficial to Tallgrass as we continue to invest capital in accretive growth opportunities.

TGE's board of directors received a proposal from Blackstone in August expressing a desire to acquire all of the outstanding Class A shares in TGE and to take the company private. The Board formed a Conflicts Committee consisting of independent directors of the Board to consider the proposal.

In mid-December, TGE entered into a definitive merger agreement that would allow Blackstone Infrastructure Partners and its affiliates (including Enagas, GIC, NPS and USS) to acquire all of the publicly held outstanding Class A shares of TGE for \$22.45 in cash per share. A Conflicts Committee consisting of independent members of TGE's board of directors negotiated the transaction, determined it was in the best interests of TGE and its public shareholders and unanimously approved the transaction.

The transaction is expected to close in the second quarter of 2020, pending satisfaction of customary conditions including approval of the merger by shareholders. Pursuant to the merger agreement, TGE agreed not to pay distributions while the transaction is pending. Upon the transaction closing, TGE will cease to be publicly traded. We will be sending shareholders a proxy statement including detailed disclosures about the proposed transaction.

Now, let's take a look at some significant events and accomplishments from 2019.

Commercial Highlights

Crude Oil Transportation Segment

- Secured additional pipeline commitments to expand Pony Express to 450 MBbl/d.
- Placed the Iron Horse pipeline into service in the Powder River Basin.
- Placed the PXP Hereford Extension into service in the D-J Basin.
- As of January 2020 we have contracted approximately 195 MBbl/d of take-or-pay transportation commitments on Pony beyond 2021.
- Reached FID on the Carpenter Extension into Wyoming.
- PXP is running full, and over the year we achieved several all-time high daily throughput levels.

Natural Gas Transportation Segment

- Began construction on the Cheyenne Connector pipeline and REX Cheyenne Hub Enhancement projects; Cheyenne Connector will play an integral role in debottlenecking the D-J Basin and the Hub Enhancement project will allow up to 1 bcf/d of gas access to REX.
- Reached FID on the Guernsey, Ohio, power plant connection, a proposed 300 Mdth/d load off of REX.
- REX renewed long-term commitments from several legacy shippers after their contracts terminated in November 2019. REX will continue to be a key outlet for production in the Rockies, and as such is actively negotiating additional long-term commitments with several other counterparties.
- In partnership with our customers, successfully settled rate cases for both TIGT and Trailblazer, avoiding costly litigation.
- Trailblazer is sold out. About 85 percent of capacity is under negotiated rate agreements that were extended through at least 2026.

Gathering, Processing and Terminalling Segment

Tallgrass Terminals

- Reached a key Plaquemines Liquids Terminal milestone by securing a consistency determination and MOU with Louisiana's Coastal Protection and Restoration Authority.
- Reduced the number of trucks on the road and increased volume potential on Pony Express by connecting new gathering systems, including Taproot, Outrigger, ARB, Rocky Mountain Midstream (Williams) and Oxy.

TMID

- > Signed a Powder River Basin agreement for 36,000 net acre-age dedication with the potential to grow.
- > Increased PRB gathering average annual volumes into Douglas Plant from 38 MMcf/d to 50 MMcf/d.

Water Business

- > Entered the Marcellus/Utica and now serve seven North American shale basins.
- > Through acquisitions and green field development, BNN increased customer base by 45 percent; customers include 139 unique clients.

Sustainability

We are committed to operating safely and responsibly. This commitment does not stop with our goal of zero unsafe behaviors. It extends to how we manage our balance sheet for financial strength and stability, how we attract, retain and develop employees, how we nurture long-term customer relationships, how we treat the people we encounter in the communities we touch and how we strive to preserve our world for future generations.

Through our membership in The Environmental Partnership, we have voluntarily committed to further reduce methane and other emissions (see page 4). We're also actively working with the Blackstone Sustainability Group to assess systems, equipment, and processes to identify and implement changes to improve the overall efficiency and reliability of our assets. This review ranges from quick fixes such as simple HVAC system improvements to major equipment modifications like Waste Heat Recovery that has the potential to generate up to 197,000 MWh of energy annually from turbine generator waste heat alone. The waste heat recovery effort is modeled after an existing application at a Trailblazer compressor station that has been operating successfully for more than 12 years.

Our water business, BNN, is commercializing BNN Appalachia Water Infrastructure Network, which will significantly reduce

truck traffic while promoting the reuse of produced water—in turn reducing freshwater demand and disposal requirements. BNN also is working with a major E&P company to develop a commercially viable water treatment system that allows produced water to be treated to a freshwater standard allowing for discharge or use in other industries. BNN's extensive water distribution and gathering pipelines across multiple basins help keep trucks off the road, mitigating the substantially higher risk and environmental footprint of trucking.

Finally, by quickly and efficiently fixing any leak on our natural gas gathering system, we have reduced lost and unaccounted for volumes on the system from about 11 percent in 2017 when we purchased the assets to less than 2 percent. We plan to strengthen these and other sustainability efforts in the years to come.

Looking Ahead

Looking ahead, we will continue to pursue a prudent growth plan fueled by organic opportunities and acquisitions. I look forward to working with our outstanding leadership team to continue to bring value to our customers, our employees, investors, business partners and communities.

The growth we've enjoyed in the past and the growth we hope to achieve in the future comes from the hard work and dedication of everyone on the Tallgrass team. Without them, none of this is possible. I want to thank them for their passion and commitment. I also want to thank our customers, suppliers, shareholders, neighbors, regulators and everyone who continues to support our company. We look forward to a prosperous future together.



William R. Moler
Chief Executive Officer

For additional information regarding TGE, please reference TGE's annual report on Form 10-K for the year ended December 31, 2019 and its other filings with the SEC, which are available as detailed below.

Additional Information and Where to Find It

In connection with the proposed transaction referred to in this material, TGE filed a preliminary proxy statement with the SEC on January 21, 2020, which was amended on February 11, 2020, and intends to file other materials with the SEC, including a proxy statement in a definitive form. TGE also expects to mail or otherwise provide to its shareholders such proxy statement regarding the proposed transaction. BEFORE MAKING ANY VOTING DECISION, TALLGRASS' SHAREHOLDERS ARE URGED TO CAREFULLY READ THE PROXY STATEMENT IN ITS ENTIRETY WHEN IT BECOMES AVAILABLE AND ANY OTHER DOCUMENTS FILED WITH THE SEC IN CONNECTION WITH THE PROPOSED TRANSACTION OR INCORPORATED BY REFERENCE THEREIN BECAUSE THEY WILL CONTAIN IMPORTANT INFORMATION ABOUT THE PROPOSED TRANSACTION AND THE PARTIES TO THE PROPOSED TRANSACTION. Investors and security holders may obtain a free copy of the proxy statement and other documents filed with the SEC (when available) by TGE through the website maintained by the SEC at <http://www.sec.gov>. Copies of the documents filed by TGE will be available free of charge on TGE's website at www.tallgrassenergy.com, in the "Investors" tab near the top of the page, or by contacting TGE's Investor Relations Department at 1-913-928-6012.

Participants in the Solicitation

TGE and its general partner's directors and executive officers may be considered participants in the solicitation of proxies with respect to the proposed transaction under the rules of the SEC. Information about the directors and executive officers of TGE's general partner may be found in its 2019 Form 10-K filed with the SEC on February 12, 2020 and any subsequent statements of changes in beneficial ownership filed with the SEC. These documents can be obtained free of charge from the sources indicated above. Additional information regarding the participants in the proxy solicitation and a description of their direct and indirect interests, by security holdings or otherwise, will also be included in any proxy statement and other relevant materials to be filed with the SEC when they become available.

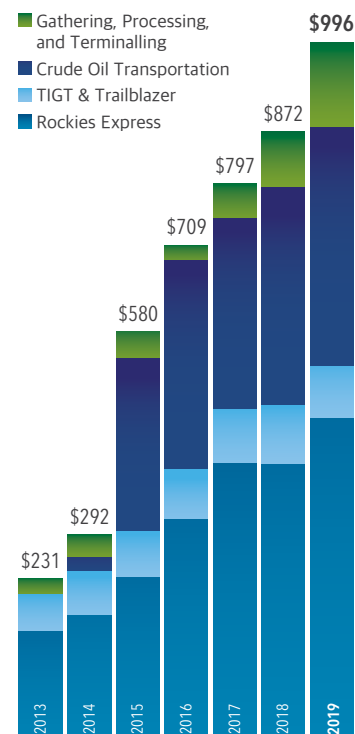
SUMMARY FINANCIAL INFORMATION

(in thousands)	Year Ended December 31, 2019
Net income attributable to TGE	\$ 248,809
Add:	
Interest expense, net ⁽¹⁾	161,429
Depreciation and amortization expense ⁽¹⁾	127,503
Distributions from unconsolidated investments	470,981
Non-cash compensation expense	31,563
Income tax expense ⁽¹⁾	70,578
Net income attributable to Exchange Right Holders	193,961
Deficiency payments, net ⁽¹⁾	16,992
Non-cash loss related to derivative instruments	272
Loss on disposal of assets ⁽¹⁾	354
Less:	
Equity in earnings of unconsolidated investments	(325,385)
Other non-cash (gain)	(724)
Adjusted EBITDA	\$ 996,333
Less:	
Cash interest cost ⁽¹⁾	(155,174)
Maintenance capital expenditures, net ⁽¹⁾	(42,287)
Current income tax expense ⁽¹⁾	(672)
Cash Available for Dividends	\$ 798,200

(1) Net of noncontrolling interest associated with less than wholly owned subsidiaries of Tallgrass Equity.

Tallgrass Energy Adjusted EBITDA*

(in millions)



*Represents Tallgrass Energy Adjusted EBITDA across the Tallgrass Energy Family of Companies. Reconciliations of this non-GAAP metric for 2013-2018 are available in the presentation dated 8/14/2019 under the Webcasts & Presentations section at www.tallgrassenergy.com.



Through its membership in The Environmental Partnership, Tallgrass has voluntarily committed to implement strategies and tactics designed to further reduce methane and volatile organic compound emissions across our assets using proven technologies. The Environmental Partnership is an organization comprised of companies committed to continuously improve the industry's environmental performance.

TALLGRASS ENERGY
2019 FORM 10-K

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

FORM 10-K

(Mark One)

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

**For the Fiscal Year Ended December 31, 2019
or**

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

Commission file number 001-37365

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

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

Delaware
(State or other Jurisdiction of Incorporation or Organization)

47-3159268
(IRS Employer Identification Number)

**4200 W. 115th Street, Suite 350
Leawood, Kansas**
(Address of Principal Executive Offices)

66211
(Zip Code)

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

<u>Title of each class</u>	<u>Trading Symbol</u>	<u>Name of each exchange on which registered</u>
Class A Shares Representing Limited Partner Interests	TGE	New York Stock Exchange

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

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes ☐ No ☒

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

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

Yes ☒ No ☐

Indicate by check mark 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.

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	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 Act). Yes ☐ No ☒

The aggregate market value of voting and non-voting common equity held by non-affiliates on June 28, 2019, the last business day of the Registrant's most recently completed second fiscal quarter (based on the closing sale price of \$21.11 of the Registrant's Class A shares, as reported by the New York Stock Exchange on such date) was approximately \$3,204.0 million. On February 12, 2020, the Registrant had 179,632,609 Class A shares and 102,136,875 Class B shares outstanding.

TALLGRASS ENERGY, 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.

Pipeline loss allowance (or PLA): Crude oil collected from customers under certain crude oil transportation arrangements.

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 I

As used in this Annual Report, unless the context otherwise requires, "we," "us," "our," the "Partnership," "TGE" and similar terms refer to Tallgrass Energy, LP, in its individual capacity or to Tallgrass Energy, LP and its consolidated subsidiaries collectively (including Tallgrass Equity, Tallgrass Energy Partners, LP and their respective subsidiaries), as the context requires. References to "Tallgrass Equity" refer to Tallgrass Equity, LLC. References to "TEP" refer to Tallgrass Energy Partners, LP. The term our "general partner" refers to Tallgrass Energy GP, LLC. References to "Tallgrass Development" or "TD" refer to Tallgrass Development, LP.

A reference to a "Note" herein refers to the accompanying Notes to Consolidated Financial Statements contained in Item 8.—Financial Statements and Supplementary Data. 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 Annual 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 Annual 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 Annual 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:

- whether the proposed Take-Private Merger (as defined in Item 1.—Business, *"Organizational Structure;"*) will be consummated before the end of the second quarter of 2020 or at all;
- whether any of the conditions to the Take-Private Merger will be satisfied;
- our ability to pay dividends to our Class A shareholders, which is impacted by, among other things, our agreement pursuant to the Take-Private Merger Agreement (as defined in Item 1.—Business, *"Organizational Structure;"*) not to pay dividends during the pendency of the transactions contemplated by the Take-Private Merger Agreement;
- our expected receipt of, and amounts of, distributions from Tallgrass Equity, which is impacted by, among other things, our agreement pursuant to the Take-Private Merger Agreement not to permit Tallgrass Equity to pay distributions on the units representing limited liability company interests in Tallgrass Equity during the pendency of the transactions contemplated by the Take-Private Merger Agreement;
- our ability to complete and integrate acquisitions, including integrating the acquisitions discussed in Item 1.—Business, *"Acquisitions;"*
- the demand for our services, including natural gas transportation and storage; crude oil transportation; and natural gas gathering and processing, crude oil storage and terminalling services, and water business services;
- our ability to successfully contract or re-contract our services;
- 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 existing and future litigation, including litigation relating to the Take-Private Merger; and
- certain factors discussed elsewhere in this Annual 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.

Item 1. Business

Overview

TGE is a limited partnership that owns, operates, acquires and develops midstream energy assets in North America and has elected to be treated as a corporation for U.S. federal income tax purposes.

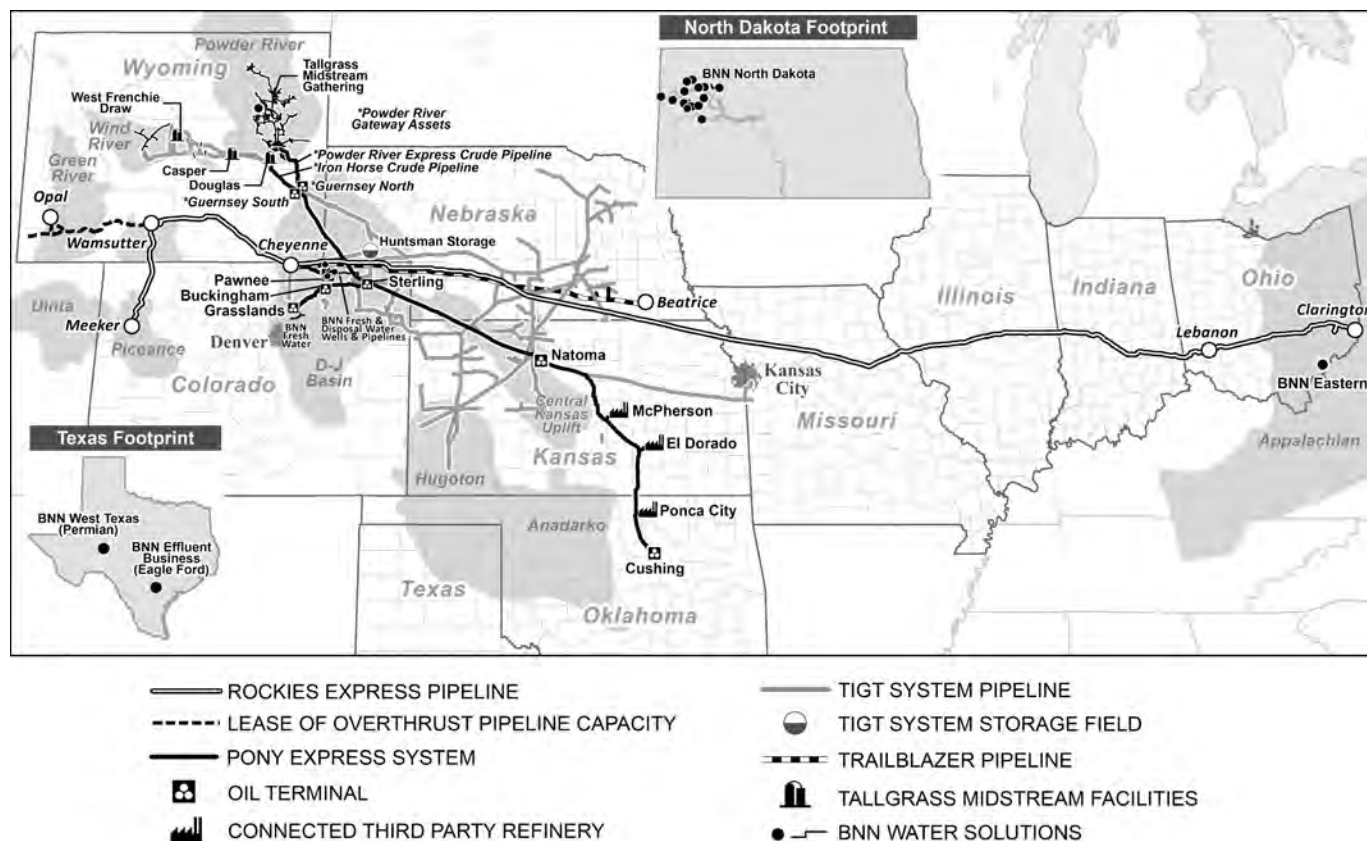
Our operations are conducted through, and our operating assets are owned by, our direct and indirect subsidiaries, including Tallgrass Equity in which we directly own an approximate 63.75% membership interest as of February 12, 2020. We are located in and provide services to certain key United States 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 an integrated natural gas storage facility;
- Crude Oil Transportation—the ownership and operation of FERC-regulated crude oil pipeline systems; 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.

Our Assets

The following map shows our primary assets, which consist of natural gas transportation and storage assets; crude oil transportation assets; natural gas gathering and processing assets; crude oil storage and terminalling assets; and water business services assets. Each of these assets are described in more detail below. Connected third party refineries are also indicated on the map below.



Natural Gas Transportation Segment

Rockies Express Pipeline. We own a 75% membership interest in Rockies Express Pipeline LLC ("Rockies Express"). Rockies Express owns the Rockies Express Pipeline, a FERC-regulated natural gas pipeline system with approximately 1,712 miles of transportation pipelines, including laterals, extending from Opal, Wyoming and Meeker, Colorado to Clarington, Ohio (the "Rockies Express Pipeline") and consists of three zones:

- Zone 1 - 328 miles of mainline pipeline from the Meeker Hub in Northwest Colorado, across Southern Wyoming to the Cheyenne Hub in Weld County, Colorado capable of transporting 2.0 Bcf/d of natural gas from west-to-east;
- Zone 2 - 714 miles of mainline pipeline from the Cheyenne Hub to an interconnect in Audrain County, Missouri capable of transporting 1.8 Bcf/d of natural gas from west-to-east; and
- Zone 3 - 643 miles of mainline pipeline from Audrain County, Missouri to Clarington, Ohio, which is bi-directional and capable of transporting 1.8 Bcf/d of natural gas from west-to-east and 2.6 Bcf/d of natural gas from east-to-west.

For the year ended December 31, 2019, approximately 98% of Rockies Express' revenues were generated under firm fee contracts.

The following tables provide information regarding the Rockies Express Pipeline for the years ended December 31, 2019, 2018, and 2017 and as of December 31, 2019:

	Year Ended December 31,		
	2019	2018	2017
Approximate average daily deliveries (Bcf/d) ⁽¹⁾	4.0	4.4	4.3

	Approximate Capacity	Total Firm Contracted Capacity ⁽²⁾	Approximate % of Capacity Subscribed under Firm Contracts	Weighted Average Remaining Firm Contract Life ⁽³⁾
West-to-east	2.0 Bcf/d	1.0 Bcf/d	49%	5 years
East-to-west	2.6 Bcf/d	2.6 Bcf/d	100%	13 years

⁽¹⁾ Reflects average total daily deliveries for the Rockies Express Pipeline, regardless of flow direction or distance traveled.

⁽²⁾ Reflects total capacity reserved under long-term firm fee contracts as of December 31, 2019.

⁽³⁾ Weighted by contracted capacity as of December 31, 2019.

TIGT System. We own a 100% membership interest in Tallgrass Interstate Gas Transmission, LLC ("TIGT"), which owns the Tallgrass Interstate Gas Transmission system, a FERC-regulated natural gas transportation and storage system with approximately 4,580 miles of varying diameter transportation pipelines serving Wyoming, Colorado, Kansas, Missouri and Nebraska (the "TIGT System"). The TIGT System includes the Huntsman natural gas storage facility located in Cheyenne County, Nebraska. The TIGT System primarily provides transportation and storage services to on-system customers such as local distribution companies and industrial users, including ethanol plants, and irrigation and grain drying operations, which depend on the TIGT System's interconnections to their facilities to meet their demand for natural gas and a majority of whom pay FERC-approved recourse rates. For the year ended December 31, 2019, approximately 94% of the TIGT System's transportation revenue was generated from contracts with on-system customers.

Trailblazer Pipeline. We own a 100% membership interest in Trailblazer Pipeline Company LLC ("Trailblazer"), which owns the Trailblazer Pipeline system, a FERC-regulated natural gas pipeline system with approximately 465 miles of transportation pipelines, including laterals, that begins along the border of Wyoming and Colorado and extends to Beatrice, Nebraska (the "Trailblazer Pipeline"). During the year ended December 31, 2019, substantially all of the Trailblazer Pipeline's operationally available long-haul capacity was contracted under firm transportation contracts.

The following tables provide information regarding the TIGT System and Trailblazer Pipeline for the years ended December 31, 2019, 2018, and 2017 and as of December 31, 2019:

	Year Ended December 31,		
	2019	2018	2017
Approximate average daily deliveries (Bcf/d)	1.3	1.3	1.2

	Approximate Capacity	Total Firm Contracted Capacity ⁽¹⁾	Approximate % of Capacity Subscribed under Firm Contracts	Weighted Average Remaining Firm Contract Life ⁽²⁾
Transportation	2.0 Bcf/d	1.7 Bcf/d	85%	6 years
Storage	15.974 Bcf ⁽³⁾	11 Bcf	66%	4 years

⁽¹⁾ Reflects total capacity reserved under long-term firm fee contracts, including backhaul service, as of December 31, 2019.

⁽²⁾ Weighted by contracted capacity as of December 31, 2019.

⁽³⁾ The FERC certificated working gas storage capacity.

NatGas. We own a 100% membership interest in Tallgrass NatGas Operator, LLC ("NatGas"), which is the operator of the Rockies Express Pipeline and receives a fee from Rockies Express as compensation for its services.

Crude Oil Transportation Segment

Pony Express System. We own a 100% membership interest in Tallgrass Pony Express Pipeline, LLC ("Pony Express"), which provides crude oil transportation to customers in Wyoming, Colorado, Kansas, and the surrounding regions. Pony Express owns an approximately 870-mile crude oil pipeline commencing in both Guernsey, Wyoming and Weld County, Colorado and terminating in Cushing, Oklahoma, with delivery points at the McPherson, El Dorado and Ponca City refineries and in Cushing, Oklahoma (the "Pony Express System"). We believe the Pony Express System is positioned as a low-cost, competitive transportation system with access to Bakken Shale, DJ Basin and Powder River Basin production.

The table below sets forth certain information regarding the Pony Express System's long-haul capacity as of December 31, 2019 and for the periods indicated:

Approximate Stated Capacity (bbls/d) ⁽¹⁾	Approximate Contractible Capacity Under Contract ⁽¹⁾⁽²⁾	Weighted Average Remaining Firm Contract Life ⁽³⁾	Approximate Average Daily Throughput (bbls/d)		
			Year Ended December 31,		
			2019	2018	2017
417,000	80%	2 years	358,442	336,314	267,734

- (1) Includes additional capacity related to the ability to inject drag reducing agent, which is an additive that increases pipeline flow efficiency, and additional capacity related to expansion projects.
- (2) We are required to make no less than 10% of stated capacity available for non-contract, or "walk-up", shippers. Approximately 80% of the remaining design capacity (or available contractible capacity) is committed under contract.
- (3) Based on the average annual reservation capacity for each such contract's remaining life.

Powder River Gateway. In January 2019, we completed the expansion of our existing joint venture with Silver Creek Midstream, LLC ("Silver Creek") and acquired a 51% membership interest in Powder River Gateway, LLC ("Powder River Gateway" or "PRG"). Powder River Gateway owns the (i) Powder River Express Pipeline (the "PRE Pipeline"), a 70-mile crude oil pipeline with a capacity of 90,000 barrels per day that transports crude oil from the Powder River Basin to Guernsey, Wyoming; (ii) Iron Horse Pipeline (the "Iron Horse Pipeline"), a 80-mile crude oil pipeline placed into service in May 2019 with a capacity of 100,000 barrels per day that transports crude oil from the Powder River Basin to Guernsey, Wyoming; and (iii) crude oil terminal facilities in Guernsey, Wyoming with approximately 600,000 barrels of crude oil storage.

Gathering, Processing & Terminalling Segment

Midstream Facilities. We own a 100% membership interest in Tallgrass Midstream, LLC ("TMID"), which owns and operates a natural gas gathering system in the Powder River Basin (the "Douglas Gathering System"). TMID also owns and operates natural gas processing plants in Casper and Douglas, Wyoming and a natural gas treating facility at West Frenchie Draw, Wyoming (collectively with the Douglas Gathering System, the "Midstream Facilities"). The Casper and Douglas plants currently have combined processing capacity of approximately 190 MMcf/d. The Casper plant also has an NGL fractionator with a capacity of approximately 3,500 barrels per day. The natural gas processed and treated at these facilities primarily comes from the Wind River Basin and the Powder River Basin, both in central Wyoming. TMID also owns and operates an NGL pipeline that transports NGLs from a processing plant in Northeast Colorado to an interconnect with Overland Pass Pipeline, and an NGL pipeline that originates at our Douglas facility and interconnects with ONEOK's Bakken NGL Pipeline. Each of our NGL pipelines are supported by 10-year leases for 100% of their respective pipeline capacity, with the lease for the NGL pipeline in Northeast Colorado having commenced in October 2015, and the lease for the NGL pipeline from our Douglas facility having commenced on January 1, 2017. During the year ended December 31, 2019, approximately 12%, 54%, and 34% of TMID's Adjusted EBITDA came from firm fee, volumetric fee, and commodity sensitive contracts, respectively.

The table below sets forth certain information regarding natural gas gathering and processing at the Midstream Facilities as of December 31, 2019 and for the years ended December 31, 2019, 2018, and 2017:

	Approximate Capacity (MMcf/d)	Approximate Average Volumes (MMcf/d)		
		Year Ended December 31,		
		2019	2018	2017
Gathering	75	50	42	37 ⁽¹⁾
Processing	190 ⁽²⁾	118	122	109

(1) Reflects approximate average gathering volumes subsequent to our acquisition of the Douglas Gathering System on June 5, 2017.

(2) The West Frenchie Draw natural gas treating facility treats natural gas before it flows into the Casper and Douglas plants and therefore does not result in additional inlet capacity.

Water Solutions. We provide water business services through our 100% membership interest in BNN Water Solutions, LLC ("Water Solutions"). Water Solutions, through its 100% membership interests in BNN Redtail, LLC ("BNN Redtail") and BNN North Dakota, LLC ("BNN North Dakota"), owns and operates a freshwater delivery and storage system and a produced water gathering and disposal system in Weld County, Colorado, a produced water disposal facility in Campbell County, Wyoming, and a produced water gathering and disposal system in North Dakota. Water Solutions is also the sole voting member and owns a 75.19% membership interest in BNN West Texas, LLC ("BNN West Texas"), which owns a produced water gathering and disposal system in Reeves and Reagan Counties, Texas that is operated by Water Solutions and owns a 63% membership interest in BNN Colorado Water, LLC ("BNN Colorado"), which owns a freshwater storage reservoir and supply pipeline in Weld County, Colorado. These systems are used to support third party exploration, development, and production of oil and natural gas. Water Solutions also sources treated wastewater from municipalities in Texas and recycles flowback water and other water produced in association with the production of oil and gas in Colorado. In April 2019, BNN Eastern, LLC ("BNN Eastern"), a newly formed subsidiary of Water Solutions, entered into a Stock Purchase Agreement to acquire all of the outstanding stock of CES Holding Company, Inc., which owns all of the issued and outstanding membership interests of K & H Partners LLC, a company doing business as Central Environmental Services ("CES"). CES owns and operates a salt water disposal facility located in the Utica and Marcellus area of Ohio. Subsequent to the closing of the CES acquisition on May 1, 2019, Water Solutions owns a 92.35% membership interest in BNN Eastern.

The table below sets forth certain information regarding the Water Solutions assets as of December 31, 2019 and for the years ended December 31, 2019, 2018, and 2017:

	Approximate Current Design Capacity (bbls/d)	Approximate Average Volumes (bbls/d)		
		Year Ended December 31,		
		2019	2018	2017
Freshwater	400,000 ⁽¹⁾	52,133	17,849	69,139
Gathering and Disposal	329,000 ⁽²⁾	182,292	98,489	31,511

(1) Represents design capacity at our BNN Redtail and BNN Colorado freshwater storage reservoir and supply pipeline.

(2) Represents the combined daily disposal well injection capacity for the BNN Redtail produced water gathering and disposal system acquired in December 2015, the BNN West Texas produced water gathering and disposal system which commenced operations by Water Solutions in March 2016, the BNN North Dakota produced water gathering and disposal system acquired in January 2018 and produced water disposal system acquired in November 2018, and the BNN Eastern produced water disposal system acquired in May 2019.

Terminals. We provide crude oil storage and terminalling services through our 100% membership interest in Tallgrass Terminals, LLC ("Terminals"). Terminals owns and operates several assets providing storage capacity and additional injection points for the Pony Express System, including the crude oil terminal near Sterling, Colorado with approximately 1.5 million bbls of storage capacity (the "Sterling Terminal"), the crude oil terminal in Weld County, Colorado with four truck unloading skids capable of receiving up to 42,000 bbls per day (the "Buckingham Terminal"), the crude oil terminal in the Central Kansas Uplift that can deliver upward of 20,000 bbls per day into the Pony Express System (the "Natoma Terminal"), and the crude oil terminal in Platteville, Colorado placed into service in August 2019 (the "Grasslands Terminal"), which has storage capacity of 300,000 bbls and connects to an extension of the Pony Express System originating in Platteville, Colorado (the "Platteville Extension"), enabling Pony Express to batch multiple common streams out of the Grasslands Terminal. Terminals also owns an approximate 60% membership interest in Deeprock Development, LLC ("Deeprock Development"), which owns crude oil terminals in Cushing, Oklahoma with approximately 4.0 million bbls of storage capacity (the "Cushing Terminal") and a 51% membership interest in the Pawnee, Colorado crude oil terminal ("Pawnee Terminal") with approximately 300,000 bbls of storage capacity.

Stanchion. We own a 100% membership interest in Stanchion Energy, LLC ("Stanchion"), which engages in the marketing of crude oil. Stanchion currently consists of three of our employees who primarily engage in the purchase and sale of crude oil.

Major Customers

For the year ended December 31, 2019, Continental Resources, Inc. accounted for approximately 10% of our revenues on a consolidated basis. The loss of this customer could have a material adverse effect on our financial results.

Organizational Structure

Our operations are conducted directly and indirectly through, and our operating assets are owned by, our subsidiaries. Our general partner is responsible for conducting our business and managing our operations.

In March 2019, pursuant to the terms of a Purchase Agreement dated January 30, 2019 (the "Purchase Agreement"), entered into among acquisition vehicles controlled by affiliates of Blackstone Infrastructure Partners ("BIP" and, such acquisition vehicles controlled by BIP, collectively, the "March 2019 Acquirors"), affiliates of Kelso & Co. ("Kelso"), affiliates of The Energy & Minerals Group ("EMG"), Tallgrass KC, LLC, an entity owned by certain current and former members of our management ("Tallgrass KC"), and the other sellers named therein (collectively, the "Sellers"), the March 2019 Acquirors acquired from the Sellers (i) 100% of the membership interests in our general partner, (ii) 21,751,018 Class A shares representing limited partner interests ("Class A shares") in us, (iii) 100,655,121 units representing limited liability company interests in Tallgrass Equity ("TE Units"), and (iv) 100,655,121 Class B shares representing limited partner interests ("Class B shares") in us, in exchange for aggregate consideration of approximately \$3.2 billion in cash, which was paid to the Sellers (the "March 2019 Blackstone Acquisition").

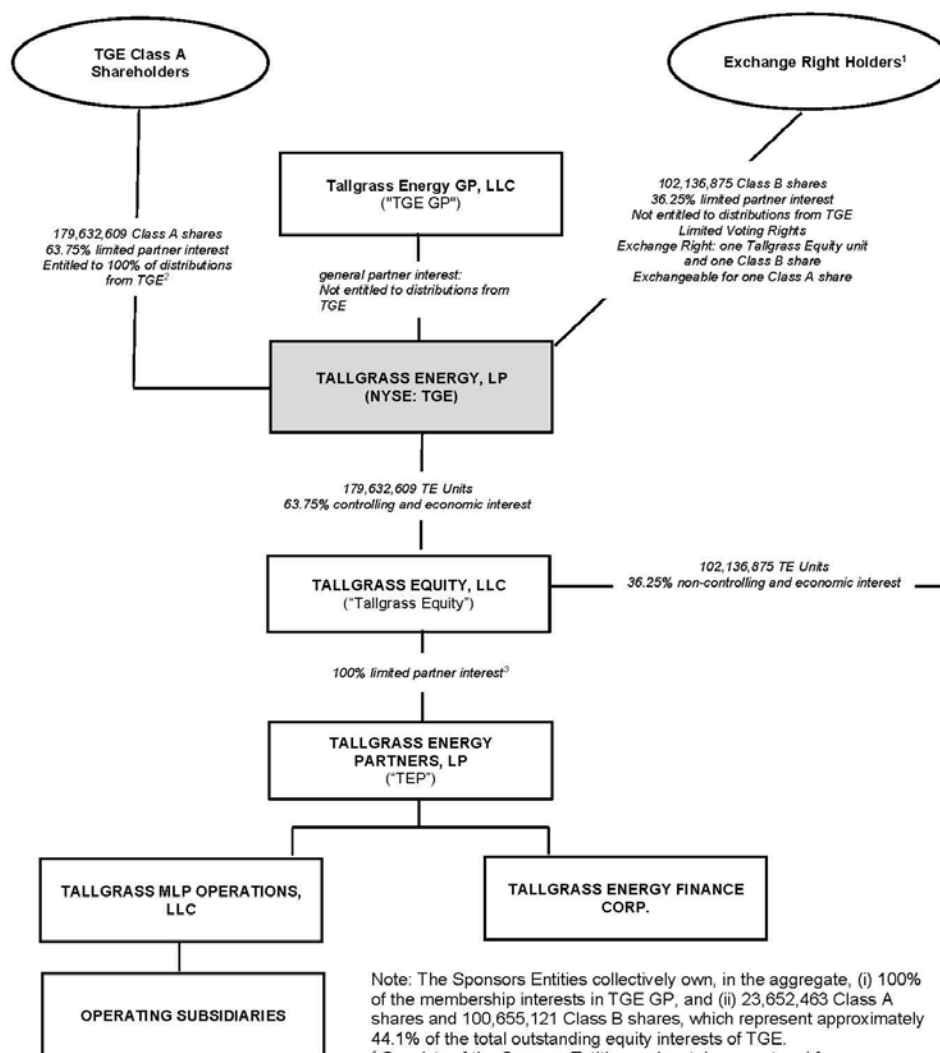
As a result of the March 2019 Blackstone Acquisition, BIP effectively controls our business and affairs through the exercise of the rights of the sole member of our general partner. Additionally, the March 2019 Acquirors, Prairie Secondary Acquiror LP, a Delaware limited partnership ("Prairie Secondary Acquiror 1"), and Prairie Secondary Acquiror E LP, a Delaware limited partnership ("Prairie Secondary Acquiror 2" and, together with Prairie Secondary Acquiror 1 and the March 2019 Acquirors, the "Sponsor Entities"), each of which are also controlled by BIP, collectively held an approximate 44.1% economic interest in us as of December 31, 2019.

On December 16, 2019, we and our general partner entered into a definitive Agreement and Plan of Merger (the "Take-Private Merger Agreement") with Prairie Private Acquiror LP, a Delaware limited partnership ("Buyer"), and Prairie Merger Sub LLC, a Delaware limited liability company and wholly owned subsidiary of Buyer ("Buyer Sub"). Buyer is an affiliate of the Sponsor Entities. Pursuant to the Take-Private Merger Agreement and subject to the satisfaction or waiver of certain conditions therein, Buyer will merge with and into TGE, with TGE surviving the merger and continuing to exist as a Delaware limited partnership (the "Take-Private Merger"). At the effective time of the Take-Private Merger (the "Effective Time"), each issued and outstanding Class A share other than the Class A shares owned by the Sponsor Entities and certain of their permitted transferees, will be converted into the right to receive \$22.45 per Class A share in cash without any interest thereon. Through the Take-Private Merger, the Sponsor Entities and the limited partners of the Buyer immediately prior to the Effective Time will become the owners of all of the outstanding Class A shares and the Class A shares will cease to be publicly traded upon closing of the Take-Private Merger. Assuming timely satisfaction of the closing conditions under the Take-Private Merger Agreement, including approval by our shareholders, the Take-Private Merger is targeted to close in the second quarter of 2020.

The holders of our outstanding Class B shares, which we refer to as the Exchange Right Holders, own an equivalent number of TE Units. The Exchange Right Holders are entitled to exercise the right to exchange their TE Units (together with an equivalent number of Class B shares) for Class A shares at an exchange ratio of one Class A share for each TE Unit exchanged. As of February 12, 2020, the Exchange Right Holders consist of the Sponsor Entities and certain current and former members of our management.

While we are structured as a limited partnership, (i) we have elected to be treated as a corporation for U.S. federal income tax purposes, (ii) neither our general partner nor the holders of our Class B shares are entitled to receive any dividends from us, and (iii) our capital structure does not include incentive distribution rights. Therefore, our dividends will be made exclusively to holders of our Class A shares. However, holders of our Class A shares and Class B shares vote together as a single class on all matters presented to our shareholders for their vote or approval, except as otherwise required by applicable law or our partnership agreement. The term "shares" used in this annual report refers to both the Class A shares and Class B shares representing limited partner interests in us. References to our "shareholders" refer to the holders of our Class A and Class B shares.

The chart below shows our organizational structure as of February 12, 2020 in a summary format.



Note: The Sponsors Entities collectively own, in the aggregate, (i) 100% of the membership interests in TGE GP, and (ii) 23,652,463 Class A shares and 100,655,121 Class B shares, which represent approximately 44.1% of the total outstanding equity interests of TGE.

¹ Consists of the Sponsor Entities and certain current and former members of our management.

² Includes the 23,652,463 Class A shares owned by the Sponsor Entities.

³ Includes (i) a 99.9% limited partner interest held directly by Tallgrass Equity, (ii) a 0.1% limited partner interest held indirectly through Tallgrass Equity Investments, LLC, a wholly owned subsidiary of Tallgrass Equity, and (iii) a general partner interest held indirectly through TEP GP.

Previous Organizational Structure

We were initially formed in 2015 as part of a reorganization involving entities that were previously controlled by Tallgrass Equity to effect our initial public offering on May 12, 2015 (the "TGE IPO"). As of the closing of the TGE IPO in May 2015, our sole cash-generating asset was a controlling membership interest in Tallgrass Equity and Tallgrass Equity's sole cash-generating assets consisted of direct and indirect partnership interests in TEP, which was a publicly traded limited partnership at the time. Prior to the March 2019 Blackstone Acquisition described above, the sole member of our general partner was Tallgrass Energy Holdings, LLC ("Tallgrass Energy Holdings"), which was primarily owned by Kelso, EMG and Tallgrass KC. Tallgrass Energy Holdings effectively controlled our business and affairs through the exercise of its rights as the sole member of our general partner until the closing of the March 2019 Blackstone Acquisition.

Prior to the TD Merger discussed below, Tallgrass Energy Holdings was the general partner of Tallgrass Development. Historically, TEP acquired a number of its assets from Tallgrass Development. In connection with TEP's initial public offering in May 2013 (the "TEP IPO"), Tallgrass Development contributed to TEP 100% of the membership interests in TIGT and TMID. Following the TEP IPO, TEP acquired the following additional assets from Tallgrass Development: (1) in April 2014, a 100% membership interest in Trailblazer, (2) in four separate transactions, the most recent of which was effective on February 1, 2018, a 100% membership interest in Pony Express, (3) in January 2017, a 100% membership interest in NatGas and Terminals, (4) in March 2017, a 24.99% membership interest in Rockies Express, and (5) effective February 1, 2018, a 100% membership interest in Tallgrass Operations, LLC, which owned certain administrative assets consisting primarily of information technology assets. In addition, in May 2016 Tallgrass Development assigned to TEP its right to purchase a 25% membership interest in Rockies Express from a unit of Semptra U.S. Gas and Power ("Semptra") pursuant to the purchase agreement originally entered into between Tallgrass Development's wholly-owned subsidiary and Semptra in March 2016.

On February 7, 2018, Tallgrass Development merged into Tallgrass Development Holdings, LLC, a wholly-owned subsidiary of Tallgrass Equity (the "TD Merger"). As a result of the TD Merger, Tallgrass Equity acquired a 25.01% membership interest in Rockies Express and an additional 5,619,218 TEP common units. As consideration for the acquisition, TGE and Tallgrass Equity issued 27,554,785 TGE Class B shares and TE Units, valued at approximately \$644.8 million based on the closing price on February 6, 2018, to the limited partners of Tallgrass Development.

On March 26, 2018, we entered into an Agreement and Plan of Merger (the "TEP Merger Agreement") with Tallgrass Equity, Tallgrass MLP GP, LLC, a Delaware limited liability company and the general partner of TEP ("TEP GP"), and Razor Merger Sub, LLC, a Delaware limited liability company. The merger transaction contemplated by the TEP Merger Agreement (the "TEP Merger") was completed effective June 30, 2018, and as a result, 47,693,097 TEP common units held by the public were converted into the right to receive Class A shares of TGE at an exchange ratio of 2.0 Class A shares for each outstanding TEP common unit, TEP's incentive distribution rights were cancelled, TEP's common units ceased being publicly traded, and 100% of TEP's equity interests are now owned by Tallgrass Equity and its subsidiaries.

Acquisitions

The acquisition of midstream assets and businesses that are strategic and complementary to our existing operations constitutes an integral component of our business strategy and growth objectives. Such assets and businesses include natural gas transportation and storage; crude oil transportation; and natural gas gathering and processing, crude oil storage and terminalling services, and water business service assets and other energy assets that have characteristics and provide opportunities similar to our existing business lines and enable us to leverage our assets, knowledge and skill sets. Below are summaries of significant acquisitions completed in 2019, as discussed in Note 3 – *Acquisitions and Dispositions*.

- *Acquisition of CES.* In April 2019, we entered into a Stock Purchase Agreement to acquire all of the outstanding stock of CES Holding Company, Inc., which owns all of the issued and outstanding membership interests of CES. On May 1, 2019, the acquisition closed for cash consideration of approximately \$52 million paid at closing, and the issuance of a 7.65% membership interest in BNN Eastern to one of the sellers in the transaction.
- *Joint Venture with Silver Creek.* In February 2018, we entered into an agreement with Silver Creek to form a joint venture to own the Iron Horse Pipeline. Effective January 1, 2019, the joint venture between us and Silver Creek was expanded through contributions to Powder River Gateway. The expanded joint venture operates under the name Powder River Gateway, LLC and owns the Iron Horse Pipeline, the Powder River Express Pipeline, and crude oil terminal facilities in Guernsey, Wyoming. Effective January 1, 2019, we own a 51% membership interest in Powder River Gateway and operate the joint venture.

Growth Projects

Our extensive asset base and our relationships with customers provide us with opportunities for internal growth through the construction of additional assets to build upon our existing asset base. The following growth projects are currently ongoing and will extend throughout 2020 and beyond:

- *Cheyenne Connector Pipeline.* In November 2019, we entered into a joint venture agreement with DCP Cheyenne Connector, LLC ("DCP") to jointly-own Cheyenne Connector, LLC ("Cheyenne Connector"). As of December 31, 2019, we own a 50% membership interest in Cheyenne Connector, which is developing the Cheyenne Connector Pipeline, a new FERC-regulated pipeline lateral in Northeast Colorado that will transport natural gas from the DJ Basin in Weld County to the Rockies Express Pipeline's Cheyenne Hub, discussed below. The Cheyenne Connector Pipeline will be a large-diameter pipeline approximately 70 miles long, with an initial capacity of at least 600 mmcf/d. The Cheyenne Connector Pipeline is expected to be in-service in the first half of 2020.
- *Cheyenne Hub Enhancement Project.* The Rockies Express Pipeline's Cheyenne Hub is an existing natural gas facility owned and operated by Rockies Express Pipeline in northern Weld County. At the Cheyenne Hub, the existing Rockies Express Pipeline intersects and/or connects with numerous other natural gas pipelines. The Cheyenne Hub Enhancement Project consists of modifications to the Rockies Express Pipeline's Cheyenne Hub to accommodate firm receipt and delivery interconnectivity among multiple natural gas pipelines with various operating pressures and will provide customers significant diversity in terms of market access. The first phase of the Cheyenne Hub Enhancement Project is expected to be in-service in the first half of 2020.
- *Plaquemines Liquids Terminal.* In November 2018, we entered into a joint venture agreement with Drexel Hamilton Infrastructure Fund I, L.P. ("DHIF") to jointly-own Plaquemines Liquids Terminal, LLC ("PLT"). PLT was formed with the intention of developing storage and terminalling facilities for both crude oil and refined products and export facilities capable of loading Suezmax and Very Large Crude Carriers ("VLCC") vessels for international delivery on a site located on the Mississippi River in Plaquemines Parish, Louisiana. We made an initial cash contribution of \$30.7 million in exchange for a 100% preferred membership interest and a 80% common membership interest. DHIF contributed any and all assets and rights related to the project in exchange for a 20% common membership interest and the right to receive certain special distributions. Also in November 2018, PLT entered into an agreement with the Plaquemines Port & Harbor Terminal District to lease the land site on which PLT expects to construct the facilities. The project is currently under development.

Competition

All of our businesses face strong competition for acquisitions and development of new projects from both established and start-up companies. Competition may increase the cost to acquire existing facilities or businesses and may result in fewer commitments and lower returns for new pipelines or other development projects. Our competitors may have greater financial resources than we possess or may be willing to accept lower returns or greater risks. Competition differs by region and by the nature of the business or the project involved.

Additionally, pending and future construction projects, if and when brought online, may also compete with our natural gas transportation, storage, gathering and processing services, crude oil transportation, storage, gathering and terminalling services, and water transportation, gathering, recycling and disposal services. Further, natural gas as a fuel, and fuels derived from crude oil, compete with other forms of energy available to users, including electricity, coal, other liquid fuels and alternative energy. Increased demand for such forms of energy at the expense of natural gas or fuels derived from crude oil could lead to a reduction in demand for our services. Moreover, several other factors may influence the demand for natural gas and crude oil which in turn influences the demand for our services, including price changes, the availability of natural gas and crude oil and other forms of energy, the level of business activity, conservation, legislation and governmental regulations, weather, and the ability to convert to alternative fuels.

Our principal competitors in our natural gas transportation and storage business include companies that own major natural gas pipelines, such as Enbridge Inc., Kinder Morgan Inc., Northern Natural Gas Company, Southern Star Central Gas Pipeline, Inc., Energy Transfer LP, and The Williams Companies Inc., some of whom also have existing storage facilities connected to their transportation systems that compete with our storage facilities.

Pony Express encounters competition in the crude oil transportation business. A number of pipeline companies compete with Pony Express to service takeaway volumes in markets that Pony Express currently serves, including pipelines owned and operated by Sinclair Oil Corporation, Plains All American Pipeline, L.P., Suncor Energy Inc., Magellan Midstream Partners, L.P., Occidental Petroleum Corporation, NGL Energy Partners LP, Energy Transfer LP, and Enbridge Inc. Pony Express also competes with rail facilities, which can provide more delivery optionality to crude oil producers and marketers looking to capitalize on basis differentials between two primary crude oil price benchmarks (West Texas Intermediate Crude and Brent Crude), and with refineries that source barrels in areas served by Pony Express.

We also experience competition in the natural gas processing business. Our principal competitors for processing business include other facilities that service its supply areas, such as the other regional processing and treating facilities in the greater Powder River Basin which include plants owned and operated by Kinder Morgan, Inc., ONEOK, Inc., Western Midstream Partners, LP, Crestwood Equity Partners, LP, and Meritage Midstream Services II, LLC. In addition, due to the competitive nature of the liquids-rich plays in the Wind River Basin and Powder River Basin, it is possible that one of our competitors could build additional processing facilities that service our supply areas. In addition, Terminals encounters competition in the crude oil storage and terminalling business from facilities owned by Magellan Midstream Partners, L.P., NGL Energy Partners LP, Plains All American, L.P., Blueknight Energy Partners, L.P., Energy Transfer, LP, and Enbridge Inc. Further, we experience competition in the water business services. Our principal competitors in such business are other midstream companies, such as NGL Energy Partners LP, Rattler Midstream LP, and Select Energy Services, Inc. who compete with Water Solutions in areas of concentrated production activity.

Regulatory Environment

Federal Energy Regulatory Commission

We provide open-access interstate transportation service on our natural gas transportation systems pursuant to tariffs approved by the FERC. As interstate transportation and storage systems, the rates, terms of service and continued operations of the Rockies Express Pipeline, the TIGT System and the Trailblazer Pipeline are subject to regulation by the FERC under, among other statutes, the Natural Gas Act of 1938, or NGA, the Natural Gas Policy Act of 1978, or the NGPA, and the Energy Policy Act of 2005, or EPAct 2005. The rates and terms of service on the Pony Express System, the PRE Pipeline, and the Iron Horse Pipeline are subject to regulation by the FERC under, among other statutes, the Interstate Commerce Act, or the ICA, and the Energy Policy Act of 1992. We provide interstate transportation service on the Pony Express System, the PRE Pipeline and the Iron Horse Pipeline pursuant to tariffs on file with the FERC. Our NGL pipeline that interconnects with Overland Pass Pipeline is leased to a third party who has obtained a waiver for itself from the FERC from the tariff, filing and reporting requirements of the ICA, and our NGL pipeline that interconnects with ONEOK's Bakken NGL Pipeline is leased to a third party who is obligated to operate the leased pipeline in conformance with the ICA as a FERC regulated NGL pipeline.

The FERC has jurisdiction over, among other things, the construction, ownership and commercial operation of pipelines and related facilities used in the transportation and storage of natural gas in interstate commerce, including the modification, extension, enlargement and abandonment of such facilities. The FERC also has jurisdiction over the rates, charges and terms and conditions of service for the transportation and storage of natural gas in interstate commerce. The FERC exercises its ratemaking authority by applying cost-of-service principles to limit the maximum and minimum levels of tariff-based recourse rates; however, it also allows for discounted or negotiated rates as an alternative to cost-based rates and may grant market-based rates in certain circumstances. In addition, FERC regulations also restrict interstate natural gas pipelines from sharing certain transportation or customer information with marketing affiliates and require that the transmission function personnel of interstate natural gas pipelines operate independently of the marketing function personnel of the pipeline or its affiliates.

The FERC's authority over interstate crude oil pipelines is less broad than its authority over interstate natural gas pipelines and includes oversight of rates, rules and regulations for service, the form of tariffs governing service, the maintenance of accounts and records, and depreciation and amortization policies.

FERC; Market Behavior Rules; Posting and Reporting Requirement; Other Enforcement Authorities

EPAct 2005, among other matters, amended the NGA to add an anti-manipulation provision that makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations to be prescribed by the FERC and, furthermore, provides the FERC with additional civil penalty authority. The FERC adopted rules implementing the anti-manipulation provision of EPAct 2005 that make it unlawful for any entity, directly or indirectly in connection with the purchase or sale of natural gas transportation services subject to the jurisdiction of the FERC to (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) engage in any act or practice that operates as a fraud or deceit upon any person.

These anti-manipulation rules apply to interstate gas pipelines and storage companies and intrastate gas pipelines and storage companies that provide interstate services as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. EPAct 2005 also amended the NGA and the NGPA to give the FERC authority to impose civil penalties for violations of these statutes of more than \$1 million per day per violation. In connection with this enhanced civil penalty authority, the FERC issued policy statements on enforcement to provide guidance regarding the enforcement of the statutes, orders, rules and regulations it administers, including factors to be considered in determining the appropriate enforcement action to be taken. Should we fail to comply with all applicable FERC-administered statutes, rule, regulations and orders, we could be subject to substantial penalties and fines, including the disgorgement of unjust profits.

EPAct 2005 also amended the NGA to authorize the FERC to facilitate price transparency in markets for the sale or transportation of physical natural gas in interstate commerce. The FERC has taken steps to enhance its market oversight and monitoring of the natural gas industry by adopting rules that (1) require buyers and sellers of annual quantities of 2,200,000 MMBtu or more of gas in any year to report by May on the aggregate volumes of natural gas they purchased or sold at wholesale in the prior calendar year; (2) report whether they provide prices to any index publishers and, if so, whether their reporting complies with the FERC's policy statement on price reporting; and (3) increase the internet posting obligations of interstate pipelines.

In addition, the Commodity Futures Trading Commission, or CFTC, is directed under the Commodities Exchange Act, or CEA, to prevent price manipulations for the commodity and futures markets, including the energy futures markets. Pursuant to the Dodd-Frank Wall Street Reform and Consumer Protection Act, or Dodd-Frank Act, and other authority, the CFTC has adopted anti-market manipulation regulations that prohibit fraud and price manipulation in the commodity and futures markets. The CFTC also has statutory authority to seek civil penalties of up to the greater of more than \$1 million or triple the monetary gain to the violator for violations of the anti-market manipulation sections of the CEA.

Further, the Federal Trade Commission, or FTC, has the authority under the Federal Trade Commission Act, or FTCA, and the Energy Independence and Security Act of 2007, or EISA, to regulate wholesale petroleum markets. The FTC has adopted anti-market manipulation rules, including prohibiting fraud and deceit in connection with the purchase or sale of certain petroleum products, and prohibiting omissions of material information which distort or are likely to distort market conditions for such products. In addition to other enforcement powers it has under the FTCA, the FTC can sue violators under EISA and request that a court impose fines of more than \$1 million per violation per day.

The FERC also has the authority under the ICA to regulate the interstate transportation of petroleum on common carrier pipelines, including whether a pipeline's rates or rules and regulations for service are "just and reasonable." Among other enforcement powers, the FERC can order prospective rate changes, suspend the effectiveness of rates, and order reparations for damages. In addition, the ICA imposes potential criminal liability for certain violations of the statute.

Certain Outstanding Notices Issued by the FERC

FERC Advanced Notice of Proposed Rulemaking, Revisions to Indexing Policies and Page 700 of FERC Form No. 6, Docket No. RM17-1-000

On November 2, 2016, the FERC issued an Advanced Notice of Proposed Rulemaking, under which the FERC is proposing changes to its regulation of oil pipelines in two different areas: (1) its policies regarding the permissible scope of rate increases based on its annual issuance of changes to the generic oil pipeline index, based on specific pipelines' earnings or their specific changes to costs; and (2) the reporting requirements for page 700 of FERC Form No. 6, Annual Report of Oil Pipeline Companies. The FERC's Advanced Notice of Proposed Rulemaking does not propose specific regulations, and may be followed by a Notice of Proposed Rulemaking proposing specific regulations or a Policy Statement announcing new or changed policies. Comments have been filed with the FERC by interested parties and the proceeding is pending before the FERC.

Notice of Inquiry on FERC's Pipeline Certificate Policy Statement, PL18-1-000

On April 19, 2018, the FERC issued a Notice of Inquiry regarding whether it should revise its current policy statement on its review and authorization of natural gas pipelines under Section 7 of the Natural Gas Act. The current policy statement, "Certification of New Interstate Natural Gas Pipeline Facilities - Statement of Policy," was issued in 1999. The Notice of Inquiry requested comments in four general areas: (1) the reliance on precedent agreements to demonstrate need for a proposed project; (2) the potential exercise of eminent domain and landowner interests; (3) the FERC's evaluation of alternatives and environmental effects under the National Environmental Policy Act and the Natural Gas Act; and (4) the efficiency and effectiveness of the FERC's certificate processes. Comments have been filed by interested parties and the proceeding is pending before the FERC.

Examples of Our Dockets at the FERC

TIGT 2019 Pre-Filing Settlement

On May 1, 2019, TIGT filed with the FERC a pre-filing settlement in Docket No. RP19-423-001 that establishes, among other things, settlement rates reflecting an overall decrease to recourse rates, contract extensions for maximum recourse rate firm contracts through May 31, 2023, and a rate moratorium period through May 31, 2023. The settlement also requires that TIGT file a new NGA Section 4 general rate case on June 1, 2023, provided that TIGT has not preempted this mandatory filing requirement by filing on or before June 1, 2023 for approval of a new pre-filing settlement. The settlement also provided for contract extensions for maximum recourse rate firm contracts through May 31, 2023 and established a rate moratorium that will result in TIGT filing a new rate case or pre-filing settlement on or before June 1, 2023. TIGT's settlement was approved on November 8, 2019 in an order issued by the FERC.

Trailblazer 2018 General Rate Case Filing

On June 29, 2018, the Trailblazer Pipeline filed a general rate case with the FERC pursuant to Section 4 of the NGA in Docket No. RP18-922-000. Trailblazer and its customers reached a settlement in principle on October 2, 2019. The settlement continues the bifurcated rate treatment for Trailblazer's "Existing System" and "Expansion System" and maintains the existing fuel retainage and revenue crediting mechanisms. Shippers with firm contracts on the Existing System were given the opportunity to convert their contracts to negotiated rate agreements that would terminate no earlier than December 31, 2026. A rate moratorium will be in effect through December 31, 2025. The settlement was filed with the FERC on December 20, 2019 and is currently awaiting approval from the FERC.

Cheyenne Hub Enhancement Project

On March 2, 2018, Rockies Express submitted an application pursuant to section 7(c) of the NGA 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 which we refer to as the Cheyenne Hub Enhancement Project. Rockies Express filed this certificate application in conjunction with a concurrently filed certificate application by Cheyenne Connector for the Cheyenne Connector Pipeline further described below. On September 20, 2019, the FERC issued an order approving the application. A notice to proceed with construction was issued on October 8, 2019.

Cheyenne Connector Pipeline

On March 2, 2018, Cheyenne Connector submitted an application pursuant to section 7(c) of the NGA 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' Cheyenne Hub, which we refer to as the Cheyenne Connector Pipeline. On September 20, 2019, the FERC issued an order approving the application. A notice to proceed with construction was issued on October 8, 2019.

For additional information regarding our regulatory filings with the FERC, see Note 19 – *Regulatory Matters*.

Pipeline and Hazardous Materials Safety Administration

We are also subject to safety regulations imposed by PHMSA, including those regulations requiring us to develop and maintain integrity management programs to comprehensively evaluate certain areas along our pipelines and take additional measures to protect pipeline segments located in areas, which are referred to as high consequence areas, or HCAs, where a leak or rupture could potentially do the most harm.

In January 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, or The Pipeline Safety Act of 2011, which amended the Pipeline Safety Improvement Act of 2002, increased penalties for violations of safety laws and rules, among other matters, and may result in the imposition of more stringent regulations in the next few years. This legislation also requires the U.S. Department of Transportation to study and report to Congress on other areas of pipeline safety, including expanding the reach of the integrity management regulations beyond high consequence areas, but restricts the U.S. Department of Transportation from promulgating expanded integrity management rules during the review period and for a period following submission of its report to Congress unless the rulemaking is needed to address a present condition that poses a risk to public safety, property or the environment. PHMSA issued a final rule effective October 25, 2013 that implemented aspects of the 2011 legislation. Among other things, the final rule increases the maximum civil penalties for violations of pipeline safety statutes or regulations, broadens PHMSA's authority to submit information requests, and provides additional detail regarding PHMSA's corrective action authority. PHMSA's maximum civil penalties were most recently increased in July and October, 2019. In October 2019, PHMSA also issued two final rules, effective July 1, 2020, to implement other aspects of the 2011 legislation related to the safety and integrity management of hazardous materials pipelines and onshore gas pipelines. In addition, the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016, or PIPES Act, reauthorized PHMSA's oil and gas pipeline programs through 2019 and gave PHMSA power to issue emergency orders upon finding an imminent hazard, required PHMSA to issue safety standards for underground natural gas storage facilities, set deadlines for conducting post-inspection briefings and making findings, required liquid pipeline operators to undertake new safety measures, and required certain updates to the PHMSA website. As of the end of 2019, PHMSA had not yet been reauthorized for funding through 2023, but PHMSA indicates that its pipeline safety functions can continue to function, subject to restrictions in an appropriations act.

PHMSA is also currently considering changes to its regulations. On December 14, 2016, PHMSA issued an interim final rule, or IFR, that addresses safety issues related to downhole facilities, including well integrity, well bore tubing, and casing at underground natural gas storage facilities. The IFR incorporates by reference two of the American Petroleum Institute's Recommended Practice standards and mandates certain reporting requirements for operators of underground natural gas storage facilities. Operators of natural gas storage facilities were given one year from January 18, 2017, the effective date of the IFR, to

implement this first set of PHMSA regulations governing underground storage fields. PHMSA determined, however, that it will not issue enforcement citations to any operators for violations of provisions of the IFR that had previously been non-mandatory provisions of American Petroleum Institute Recommended Practices 1170 and 1171 until one year after PHMSA issues a final rule. On October 1, 2019, PHMSA finalized new hazardous liquid pipeline safety regulations, effective July 1, 2020. The rule applies to hazardous liquid gathering (including oil) pipelines, except transportation-related flow lines. Among other things, the final rule requires additional event-driven and periodic inspections, requires the use of leak detection systems on all hazardous liquid pipelines, modifies repair criteria, and requires certain pipelines to eventually accommodate in-line inspection tools.

Also, on April 8, 2016, PHMSA published a notice of proposed rule-making, or NPRM, addressing natural gas transmission and gathering lines. The proposed rule would include changes to existing integrity management requirements and would expand assessment and repair requirements to pipelines in areas with medium population densities (referred to as Moderate Consequence Areas or MCAs), along with other changes. This NPRM builds on an Advisory Bulletin PHMSA issued in May 2012, which advised pipeline operators of anticipated changes in annual reporting requirements and that if they are relying on design, construction, inspection, testing, or other data to determine the pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing (including hydrotesting) or modifying or replacing facilities to meet the demands of such pressures, could significantly increase our costs. TIGT continues to investigate and, when necessary, report to PHMSA the miles of pipeline for which it has incomplete records for maximum allowable operating pressure, or MAOP. We are currently undertaking an extensive internal record review in view of the anticipated PHMSA annual reporting requirements. Additionally, failure to locate such records or verify maximum pressures could result in reductions of allowable operating pressures, which would reduce available capacity on our pipelines. On October 1, 2019, PHMSA issued a final rule, effective July 1, 2020, that puts in place the first third of the regulations contemplated by the 2016 NPRM; two other phases of rulemaking are expected to address the remainder of items proposed in the 2016 NPRM. The October 2019 final rule requires the completion of periodic integrity reassessments, ordinarily required once every seven years, within six months of written notice from PHMSA; requires operators to consider and account for seismicity in identifying potential threats; requires the reporting of MAOP exceedances of gas transition pipelines; and imposes the proposed record-keeping requirements to confirm MAOP. In addition, the final rule requires operators to perform integrity assessments in MCAs and Class 3 and 4 areas (involving either high density or high consequence structures) at least once by October 1, 2033, and at least once every 10 years thereafter. The final rule also sets specific standards for pressure-relief safety devices on in-line pipeline inspection tools. At the state level, several states have also passed legislation or promulgated rulemaking dealing with pipeline safety. There can be no assurance as to the amount or timing of future expenditures for pipeline integrity regulation, and actual future expenditures may be different from the amounts we currently anticipate. Regulations, changes to regulations or an increase in public expectations for pipeline safety may require additional reporting, the replacement of some of our pipeline segments, the addition of monitoring equipment and more frequent inspection or testing of our pipeline facilities. Any repair, remediation, preventative or mitigating actions may require significant capital and operating expenditures.

Pipeline Integrity Issues

The ultimate costs of compliance with the integrity management rules are difficult to predict. Changes such as advances of in-line inspection tools, identification of additional threats to a pipeline's integrity and changes to the amount of pipe determined to be located in HCAs or expansion of integrity management requirements to areas outside of HCAs can have a significant impact on the costs to perform integrity testing and repairs. In July 2018, PHMSA issued an advance notice of proposed rulemaking seeking comment on the class location requirements for natural gas transmission pipelines, and particularly the actions operators must take when class locations change due to population growth or building construction near the pipeline. The associated NPRM is expected in April 2020. We will continue pipeline integrity testing programs to assess and maintain the integrity of its existing and future pipelines as required by the U.S. Department of Transportation regulations. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines, which expenditures could be material.

From time to time, our pipelines may experience integrity issues. These integrity issues may cause explosions, fire, damage to the environment, damage to property and/or personal injury or death. In connection with these incidents, we may be sued for damages caused by an alleged failure to properly mark the locations of our pipelines and/or to properly maintain our pipelines. Depending upon the facts and circumstances of a particular incident, state and federal regulatory authorities may seek civil and/or criminal fines and penalties and we may also be subject to private civil liability for such matters.

Trailblazer

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 continued performing remediation to increase and maximize its operating capacity over the long-term and spent approximately \$21 million during 2018 for this pipe replacement and remediation work. As of October 2018, the pipeline was returned to its maximum allowable operating capacity.

In connection with TEP's 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 an annual \$1.5 million deductible. TEP has received the entirety of the \$20 million from TD pursuant to the contractual indemnity as of December 31, 2017.

Pony Express

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 portions of the pipeline that were converted from natural gas to crude oil service. Remediation work was substantially complete as of March 1, 2018.

Environmental, Health and Safety Matters

General

The ownership, operation and expansion of our assets are subject to federal, state and local laws, regulations and potential liabilities arising under or relating to the protection or preservation of the environment, natural resources and human health. These laws and regulations can restrict or impact our business activities in many ways, such as restricting the way we can handle or dispose of our wastes, requiring remedial action to mitigate pollution conditions that may be caused by our operations or that are attributable to former operations, regulating future construction activities to mitigate harm to threatened or endangered species, wetlands and migratory birds, and requiring the installation and operation of pollution control or seismic monitoring equipment. The cost of complying with these laws and regulations can be significant, and we expect to incur significant compliance costs in the future as new, more stringent requirements are adopted and implemented.

Failure to comply with existing environmental laws, regulations, permits, approvals or authorizations or to meet the requirements of new environmental laws, regulations or permits, approvals and authorizations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties and/or temporary or permanent interruptions in our operations that could influence our business, financial position, results of operations and prospects. Certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where hazardous substances, hydrocarbons or wastes have been disposed or otherwise released. The costs and liabilities resulting from a failure to comply with environmental laws and regulations could negatively affect our business, financial position, results of operations and prospects. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

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

We are also subject to the requirements of the Occupational Health and Safety Act, or OSHA, the Pipeline Safety Act and other comparable federal and state statutes. In general, we expect that it may have to increase expenditures in the future to comply with higher industry and regulatory safety standards. Such increases in expenditures could become significant over time.

Historically, our total expenditures for environmental control measures and for remediation have not been significant in relation to our consolidated financial position or results of operations. It is reasonably likely, however, that the long-term trend in environmental legislation and regulations will eventually move towards more restrictive standards. Compliance with these standards is expected to increase the cost of conducting business.

For additional information regarding Environmental, Health and Safety Matters, please read Item 1A.—Risk Factors.

Air Emissions

Our operations are subject to the federal Clean Air Act, or CAA, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including natural gas processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require

that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions (including GHG emissions, as discussed below), obtain and strictly comply with air permits containing various emissions and operational limitations and/or install emission control equipment. We may be required to incur certain capital expenditures in the future for air pollution control equipment and technology in connection with obtaining and maintaining operating permits and approvals for air emissions.

The EPA finalized a rule, effective August 2, 2016, under the New Source Performance Standard Program, or NSPS Program, to limit methane emissions from the oil and gas and transmission sectors. The rule sets additional emissions limits for volatile organic compounds, or VOCs, and regulates methane emissions for new and modified sources in the oil and gas industry. In September 2019, the EPA proposed a rule to reconsider, rescind, and amend various requirements of the NSPS standard, including removing sources in the transmission and storage segment from the regulated source category, rescinding the NSPS (including both VOC and methane requirements) applicable to those sources, and rescinding the methane-specific requirements of the NSPS applicable to sources in the production and processing segments. Alternatively, the EPA proposes to rescind the methane requirements of the NSPS applicable to all oil and natural gas sources, without removing any sources from the source category. However, the NSPS rule currently remains in effect. The EPA also finalized a rule effective August 2, 2016 regarding the alternative criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes. EPA draft guidance issued in September 2018 clarified that this rule pertains to the oil and gas industry. Also, effective January 17, 2017, the Bureau of Land Management of the U.S. Department of the Interior, or BLM, imposed new rules to reduce venting, flaring and leaks during oil and natural gas production activities on onshore federal and Indian lands. This rule was suspended, stayed, and reinstated before the BLM issued a final rule in September 2018 that rescinds and revises many of the requirements of the 2017 rule. The revision rule is being challenged in the U.S. District Court for the Northern District of California but currently remains in effect.

Developments in GHG Regulations

Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas and products produced from crude oil, are examples of GHGs. The EPA has determined that the emission of GHGs presents an endangerment to public health and the environment because emissions of such gases contribute to the warming of the Earth's atmosphere and other climatic changes. Various laws and regulations exist or are under development that seek to regulate the emission of such GHGs, including the EPA programs to control GHG emissions and state actions to develop statewide or regional programs. In recent years, the U.S. Congress has considered, but not adopted, legislation to reduce emissions of GHGs. There have also been efforts to regulate GHGs at an international level, most recently in the Paris Agreement, which was signed on April 22, 2016 by 175 countries, including the United States. The Paris Agreement will require countries to review and "represent a progression" in their intended, nationally-determined contributions, which set GHG emission reduction goals every five years beginning in 2020. However, in November 2019, the United States formally initiated its year-long withdrawal from the Paris Agreement, which will result in an effective exit as early as November 2020.

Because our operations, including our compressor stations, emit various types of GHGs, primarily methane and carbon dioxide, such new legislation or regulation could increase our costs related to operating and maintaining our facilities. Depending on the particular new law, regulation or program adopted, we could be required to incur capital expenditures for installing new emission controls on our facilities, acquire permits or other authorizations for emissions of GHGs from our facilities, acquire and surrender allowances for our GHG emissions, pay taxes related to our GHG emissions and administer and manage a GHG emissions program. We are not able at this time to estimate such increased costs; however, as is the case with similarly situated entities in the industry, they could be significant to us. While we may be able to include some or all of such increased costs in the rates charged by our pipelines, such recovery of costs in all cases is uncertain and may depend on events beyond our control including the outcome of future rate proceedings before the FERC and the provisions of any final legislation or other regulations. Similarly, while we may be able to recover some or all of such increased costs in the rates charged by our processing facilities, such recovery of costs is uncertain and may depend on the terms of our contracts with our customers. In addition, new laws, regulations, or programs adopted could also impact our customers' operations or the overall demand for fossil fuels. Any of the foregoing could have an adverse effect on our business, financial position, results of operations and prospects.

Regulation of Hydraulic Fracturing

A sizeable portion of the hydrocarbons we transport, process, and store comes from hydraulically fractured wells. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. The process typically involves the injection of water, sand and a small percentage of chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is regulated by state agencies, typically the state's oil and gas commission; however, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the federal Safe Drinking Water Act, or SDWA, and has released draft permitting guidance for hydraulic fracturing activities that use diesel in fracturing fluids in those states where the EPA is the permitting authority. A number of federal agencies, including the EPA and the U.S. Department of Energy, are analyzing, or have been requested to

review, a variety of environmental issues associated with hydraulic fracturing. In addition, some states, including those in which we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations. Other states, including states in which we operate, have restrictions on produced water storage from hydraulic fracturing operations and the operation of produced water disposal wells. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular, and in some cases, may seek to ban hydraulic fracturing entirely. Some state and local authorities have considered or imposed new laws and rules related to hydraulic fracturing, including temporary or permanent bans, additional permit requirements, operational restrictions and chemical disclosure obligations on hydraulic fracturing in certain jurisdictions or in environmentally sensitive areas.

If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for our customers to perform fracturing to stimulate production from tight formations. Restrictions on hydraulic fracturing could also reduce the volume of crude oil, natural gas, and NGLs that our customers produce, and could thereby adversely affect our revenues and results of operations.

Hazardous Substances and Waste

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, nonhazardous and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of nonhazardous and hazardous waste and may impose strict joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release or threatened release of a hazardous substance into the environment. We may handle hazardous substances within the meaning of CERCLA, or analogous state laws, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released or threatened to be released into the environment.

We also generate wastes that are subject to the Resource Conservation and Recovery Act, or RCRA, and comparable state laws. RCRA regulates both nonhazardous and hazardous solid wastes, but it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. It is possible that wastes resulting from our operations that are currently treated as non-hazardous wastes could be designated as "hazardous wastes" in the future, subjecting us to more rigorous and costly management and disposal requirements. It is also possible that federal or state regulatory agencies will adopt stricter management or disposal standards for non-hazardous wastes, including natural gas wastes. Any such changes in the laws and regulations could have a material adverse effect on our business, financial position, results of operations and prospects or otherwise impose limits or restrictions on our operations or those of our customers.

In some cases, we own or lease properties where hydrocarbons are being or have been handled for many years. Hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the locations where these hydrocarbons and wastes have been transported for treatment or disposal. We could also have liability for releases or disposal on properties owned or leased by others. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners and operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination.

Our produced water disposal operations require compliance with the Class II well standards under the federal SDWA. The SDWA imposes requirements on owners and operators of Class II wells through the EPA's Underground Injection Control program, including construction, operating, monitoring and testing, reporting and closure requirements. Our disposal wells are also subject to comparable state laws and regulations. Compliance with current and future laws and regulations regarding our produced water disposal wells may impose substantial costs and restrictions on our produced water disposal operations, as well as adversely affect demand for our produced water disposal services. State and federal regulatory agencies recently have focused on a possible connection between the operation of produced water injection wells used for oil and gas waste disposal and seismic activity and tremors. When caused by human activity, such events are called induced seismicity. In some instances, operators of produced water injection wells in the vicinity of minor seismic events have been ordered to reduce produced water injection volumes or suspend operations. Regulatory agencies are continuing to study possible linkage between produced water injection activity and induced seismicity. These developments could result in additional regulation of produced water injection wells, such regulations could impose additional costs and restrictions on our produced water disposal operations.

Federal and State Waters

The Federal Water Pollution Control Act, also known as the Clean Water Act, or the CWA, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including petroleum products, into state waters or waters of the United States. In January 2020, the EPA and the U.S. Army Corps of Engineers adopted a rule to clarify the

meaning of the term "waters of the United States" with respect to federal jurisdiction, in direct response to a 2015 final rule that many interested parties believed expanded federal jurisdiction under the CWA. The 2015 rule was heavily litigated in federal courts at both the appellate and district court levels. It is anticipated that the 2020 rule defining "waters of the United States" will also be subject to court challenge.

Regulations promulgated pursuant to the CWA and analogous state laws require that entities that discharge into federal and/or state waters obtain National Pollutant Discharge Elimination System, or NPDES, permits and/or state permits authorizing these discharges. The CWA and analogous state laws assess administrative, civil and criminal penalties for discharges of unauthorized pollutants into the water and impose substantial liability for the costs of removing spills from such waters. In addition, the CWA and analogous state laws require that individual permits or coverage under general permits be obtained by covered facilities for discharges of storm water runoff. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater. We believe that we are in substantial compliance with the CWA permitting requirements as well as the conditions imposed thereunder and that continued compliance with such existing permit conditions will not have a material effect on our results of operations.

The primary federal law related to oil spill liability is the Oil Pollution Act, or OPA, which amends and augments oil spill provisions of the CWA and imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. Spill prevention, control and countermeasure requirements of federal laws and analogous state laws require us to maintain spill prevention control and countermeasure plans. These laws also require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon tank spill, rupture or leak. Regulations promulgated pursuant to OPA further require certain facilities to maintain oil spill prevention and oil spill contingency plans. A liable "responsible party" includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge, or in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, we may be liable for costs and damages.

Endangered Species

The Endangered Species Act, or ESA, restricts activities that may affect endangered or threatened species or their habitats. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the designation of previously unlisted endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans or limit future development in the affected areas.

National Environmental Policy Act

The National Environmental Policy Act, or NEPA, establishes a national environmental policy and goals for the protection, maintenance and enhancement of the environment and provides a process for implementing these goals within federal agencies. A major federal agency action having the potential to significantly impact the environment requires review under NEPA and, as a result, many activities requiring FERC or other federal approval must undergo a NEPA review. A NEPA review can create delays and increased costs that could materially adversely affect our operations.

Employee Safety

We are subject to the requirements of OSHA and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with OSHA requirements, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

Seasonality

Weather generally impacts natural gas demand for power generation, heating purposes and other natural gas usages, which in turn influences the value of transportation and storage. Price volatility also affects gas prices, which in turn influences drilling and production. Peak demand for natural gas typically occurs during the winter months, caused by heating demand. Nevertheless, because a high percentage of our natural gas transportation and storage and crude oil transportation revenues are derived from firm capacity reservation fees under long-term firm fee contracts, our revenues attributable to those segments are not generally seasonal in nature. We experience some seasonality in our processing segment, as volumes at our processing facilities are slightly higher in the summer months. We also experience some seasonality in our maintenance, repair, overhaul, integrity, and other projects, as warm weather months are most conducive to efficient execution of these activities.

Title to Properties and Rights-of-Way

Our real property generally falls into two categories: (i) parcels that we own in fee and (ii) parcels in which our interest derives from leases, easements, rights-of-way, permits, surface use agreements, or licenses from landowners or governmental authorities, permitting the use of such land for our operations. We believe that we have satisfactory title to the material portions of the land on which our pipelines and facilities are owned by us in fee title. The remainder of the land on which our pipelines and facilities are located are held by us pursuant primarily to leases, easements, rights-of-way, permits, surface use agreements or licenses between us, as grantee, and a third party, as grantor. We believe that we have satisfactory rights to all of the material parcels in which our interest derives from leases, easements, rights-of-way, permits, surface use agreements, and licenses.

Insurance

Our general partner obtains insurance coverage for us and our subsidiaries. This insurance program includes general and excess liability insurance, auto liability insurance, workers' compensation insurance, pollution, cyber security, business interruption and property and director and officer liability insurance. All insurance coverage is in amounts which management believes are reasonable and appropriate.

Employees

We are managed and operated by the board of directors and executive officers of our general partner. As of December 31, 2019, we employed approximately 800 full-time employees through Tallgrass Management, LLC ("Tallgrass Management"), which is a wholly-owned subsidiary of Tallgrass Equity.

Available Information

We make certain filings with the SEC, including our Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments and exhibits to those reports. We make such filings available free of charge through our website, www.tallgrassenergy.com, as soon as reasonably practicable after they are filed with the SEC. The filings are also available through the SEC's website, www.sec.gov. Our press releases and recent presentations are also available on our website.

Item 1A. Risk Factors

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

Risk Factors Related to the Take-Private Merger

Failure to complete, or significant delays in completing, the Take-Private Merger could negatively affect the trading price of our Class A shares and our future business and financial results.

Completion of the Take-Private Merger is not assured and is subject to risks, including the risks that approval of the Take-Private Merger by our shareholders is not obtained or that other closing conditions are not satisfied. If the Take-Private Merger is not completed, or if there are significant delays in completing the Take-Private Merger, we would be subject to several risks, including the following:

- a decline in the price of our Class A shares due to the fact that the current price reflects a market assumption that the Take-Private Merger will be completed;
- we may owe the Buyer a termination fee of \$70 million under the terms and conditions of the Take-Private Merger Agreement;
- we will have incurred certain significant costs relating to the Take-Private Merger; and
- the attention of our management will have been diverted to the Take-Private Merger rather than our own operations and pursuit of other opportunities that could have been beneficial to us.

Class A shareholders will not receive dividends with respect to their Class A shares during the pendency of the transactions contemplated by the Take-Private Merger Agreement.

Pursuant to the Take-Private Merger Agreement, we have agreed to not pay dividends with respect to our Class A shares and to not permit Tallgrass Equity to pay any distributions on its TE Units during the pendency of the transactions contemplated by the Take-Private Merger Agreement, in each case, without the prior written consent of Buyer. In the event the Take-Private Merger Agreement is terminated, the board of directors of our general partner will promptly fix a record date and declare and pay a dividend

to the holders of Class A shares in an amount equal to the amount of dividends that the board determines would have otherwise been paid during the pendency of the transactions contemplated by the Take-Private Merger Agreement, all in accordance with our partnership agreement.

Lawsuits have been filed against TGE and the board of directors of our general partner challenging the Take-Private Merger, and any injunctive relief or adverse judgment for monetary damages could prevent the Take-Private Merger from occurring or could materially adversely affect our business, financial condition and operating results.

As of February 7, 2020, TGE and the board of directors of our general partner are named defendants in three purported class action lawsuits brought by Class A shareholders and three lawsuits brought by Class A shareholders only on behalf of the named plaintiff, each of which have been filed in U.S. federal district court, challenging under the federal securities laws the sufficiency of the disclosures made in the preliminary proxy statement filed with the SEC on January 21, 2020 regarding the Take-Private Merger. The plaintiffs in each lawsuit seek to enjoin the defendants from proceeding with or consummating the Take-Private Merger and, to the extent that the Merger is implemented before relief is granted, the plaintiff in one of the lawsuits seeks to have the Take-Private Merger rescinded. The plaintiffs in each lawsuit also seek money damages and an award of costs and attorneys' and experts' fees. Class action lawsuits are very common in connection with acquisitions of public companies, regardless of any merits related to the underlying transaction, and additional similar lawsuits may be filed.

One of the conditions to consummating the Take-Private Merger is that no injunction or other order prohibiting or otherwise preventing the consummation of the Take-Private Merger shall have been issued by any governmental authority. Consequently, if any lawsuit is successful in obtaining an injunction preventing the parties to the Take-Private Merger Agreement from consummating the Take-Private Merger, such injunction may prevent the Take-Private Merger from being completed in the expected time frame, or at all, which will delay or prevent the holders of Class A shares from receiving the merger consideration. An adverse judgment, as well as the costs of the defense of such lawsuits and other effects of such litigation, could have a material adverse effect on our business, financial condition and operating results.

While the Take-Private Merger Agreement is in effect, we may be limited in our ability to pursue other business opportunities, and our business may be otherwise adversely affected.

Pursuant to the Take-Private Merger Agreement, we have agreed to refrain from taking certain actions with respect to our business and financial affairs pending completion of the Take-Private Merger or termination of the Take-Private Merger Agreement, including (i) certain restrictions on our ability to enter into transactions and capital projects involving costs in excess of \$50 million and (ii) certain restrictions on our ability to incur indebtedness in excess of \$25 million. These restrictions could be in effect for an extended period of time.

In addition to the economic costs associated with pursuing a merger, our management continues to devote substantial time and other resources to the proposed transaction and related matters, which could limit our ability to pursue other business opportunities, including potential expansion capital projects, acquisitions, joint venture activities and other transactions. If we are unable to pursue such other business opportunities, our growth prospects and the long-term strategic position of our business could be adversely affected.

It is possible that some customers, suppliers and other persons with whom we have business relationships may delay or defer certain business decisions or might decide to seek to terminate, change or renegotiate their relationship with us in connection with the pending Take-Private Merger, which could negatively affect our revenues, earnings and cash available for distribution, as well as the market price of our Class A shares, regardless of whether the Take-Private Merger is completed.

Furthermore, the uncertainty surrounding the approval of the Take-Private Merger proposal may adversely affect our ability to attract and retain qualified personnel. We operate in an industry that currently experiences a high level of competition among different companies for qualified and experienced personnel. The uncertainty relating to the consummation of the Take-Private Merger may increase the risk that we could experience higher than normal rates of attrition or that we could experience increased difficulty in attracting qualified personnel or incur higher expenses to do so. High levels of attrition among the management and employee personnel necessary to operate our business or difficulties or increased expense incurred to replace any personnel who leave, could materially adversely affect our business or results of operations.

The Take-Private Merger may not be consummated even if our shareholders approve the Take-Private Merger proposal.

The Take-Private Merger Agreement contains conditions that, if not satisfied or waived, may prevent, delay or otherwise result in the Take-Private Merger not occurring, even if our shareholders have voted to approve the Take-Private Merger proposal. We cannot predict with certainty whether and when any of the conditions to the completion of the Take-Private Merger will be satisfied. In addition, the conflicts committee of the board of directors of our general partner can agree with Buyer not to consummate the Take-Private Merger even if our shareholders approve the Take-Private Merger proposal and the conditions to the closing of the Take-Private Merger are otherwise satisfied.

If the Take-Private Merger does not occur, neither we nor our shareholders will benefit from the expenses we have incurred in the pursuit of the Take-Private Merger.

The Take-Private Merger may not be completed. If the Take-Private Merger is not completed, and the reasons for such failure to complete the transaction do not obligate the Buyer to pay us a termination fee pursuant to the Take-Private Merger Agreement, we will have incurred substantial expenses for which no ultimate benefit will have been received by us. In connection with the Take-Private Merger, we have paid expenses of approximately \$2.8 million through January 31, 2020 and will continue to incur expenses consisting of independent advisory, accounting and legal fees, and financial printing and other related charges, much of which will be incurred even if the Take-Private Merger is not completed. In addition, if the Take-Private Merger Agreement is terminated by the Buyer under certain circumstances specified in the Take-Private Merger Agreement, we will be required to pay a \$70 million termination fee.

The Take-Private Merger is a taxable transaction for U.S. federal income tax purposes, and the U.S. federal income tax consequences to our shareholders will depend on each shareholder's particular situation.

The receipt of cash in exchange for our Class A shares in the Take-Private Merger will be a taxable transaction for U.S. federal income tax purposes. The U.S. federal income tax consequences of the Take-Private Merger, including whether a shareholder will be subject to U.S. federal income tax and, if subject to U.S. federal income tax, the applicable tax rate and the amount and character of any gain or loss recognized, will vary depending on each shareholder's particular circumstances. These circumstances include, among many others, the U.S. federal income tax classification of the shareholder, whether the shareholder is a "United States person" (as defined in the Internal Revenue Code of 1986, as amended (the "Code")) or has certain other relationships with the United States, whether the Class A shares were held as "capital assets" within the meaning of the Code, the amount of cash received, the adjusted tax basis of the Class A shares exchanged, and how long the shareholder owned the Class A shares prior to the exchange.

Risks Related to Our Business

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

We may not have sufficient available cash each quarter to enable us to pay the quarterly cash dividend at the current dividend level or at all, including, in the event the Take-Private Merger Agreement is terminated, in respect of quarters during which the transactions contemplated by the Take-Private Merger Agreement were pending. The amount of cash we have available for dividends on our Class A shares principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the level of firm services we provide to customers pursuant to firm fee contracts and the volume of customer products we transport, store, process, gather, treat and dispose using our assets;
- our ability to renew or replace expiring long-term firm fee contracts with other long-term firm fee contracts;
- the creditworthiness of our customers, particularly customers who are subject to firm fee contracts;
- our ability to source, complete and integrate acquisitions;
- the level of production of crude oil, natural gas and other hydrocarbons and the resultant market prices of natural gas, NGLs, crude oil and other hydrocarbons;
- the actual and anticipated future prices, and the volatility thereof, of natural gas, crude oil and other commodities;
- changes in the fees we charge for our services, including firm services and interruptible services;
- our ability to identify, develop, and complete internal growth projects or expansion capital expenditures on favorable terms to improve optimization of our current assets;
- regional, domestic and foreign supply and perceptions of supply of natural gas, crude oil and other hydrocarbons;
- the level of demand and perceptions of demand in end-user markets we directly or indirectly serve;
- applicable laws and regulations affecting our and our customers' business, including the market for natural gas, crude oil, other hydrocarbons and water, the rates we can charge on our assets, how we contract for services, our existing contracts, our operating costs or our operating flexibility;
- the effect of worldwide energy conservation measures;
- prevailing economic conditions;
- the effect of seasonal variations in temperature and climate on the amount of customer products we are able to transport, store, process, gather, treat and dispose using our assets;

- the realized pricing impacts on revenues and expenses that are directly related to commodity prices;
- the level of competition from other midstream energy companies in our geographic markets;
- the level of our operating and maintenance costs;
- damage to our assets and surrounding properties caused by earthquakes, floods, fires, severe weather, explosions and other natural disasters or acts of terrorism;
- outages in our assets;
- the relationship between natural gas and NGL prices and resulting effect on processing margins; and
- leaks or accidental releases of hazardous materials into the environment, whether as a result of human error or otherwise.

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

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

If we are not able to renew or replace expiring customer contracts at favorable rates or on a long-term basis, our financial condition, results of operations, cash flows and ability to make quarterly cash dividends to our Class A shareholders will be adversely affected.

A substantial majority of our contracts for transporting, storing, and processing our customers' products on our systems are long-term firm fee contracts with terms of various durations. For the year ended December 31, 2019, approximately 86% of our natural gas transportation and storage revenues were generated under long-term firm fee transportation and storage contracts and approximately 81% of our crude oil transportation revenues were generated under long-term firm fee transportation contracts. As of December 31, 2019, the weighted average remaining life of our long-term natural gas transportation contracts and natural gas storage contracts at TIGT and Trailblazer was approximately six years and four years, respectively, and the weighted average remaining life of our crude oil transportation contracts at Pony Express was approximately two years.

A significant amount of Rockies Express' revenue in 2018 and 2019 was generated by long-term west-to-east contracts that have expired in 2019. The re-contracting of the capacity made available from these expirations has been at lower rates than those expiring contracts and we expect the re-contracting of any remaining capacity for west-to-east transport will also be at lower rates. In addition, a significant portion of the long-term contracts for the Pony Express Pipeline expired in 2019 or will expire in 2020. As a result, we have been subject to prevailing market rates when contracting the capacity utilized under these expiring contracts.

We may be unable to maintain the long-term nature and economic structure of our current contract portfolio over time. Depending on prevailing market conditions at the time of a contract renewal, our transportation, storage and processing customers with long-term fee-based contracts may desire to enter into contracts with reduced fees, and may be unwilling to enter into long-term contracts at all.

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

- the level of existing and new competition to provide competing services to our markets;
- the macroeconomic factors affecting crude oil and natural gas economics for our current and potential customers;
- the balance of supply and demand for natural gas, crude oil and other hydrocarbons, on a short-term, seasonal and long-term basis, in the markets we directly and indirectly serve;

- the extent to which the current and potential customers in our markets are willing to provide firm fee commitments on a long-term basis;
- significant, prolonged low natural gas, crude oil, or other commodity prices, which could affect supply and demand for natural gas, crude oil and other hydrocarbons; and
- the effects of federal, state or local laws or regulations on the contracting practices of us and our customers.

During periods of price reduction and high volatility in the commodity markets, we expect customers will generally be less likely to enter into long-term firm fee contracts, and even if they enter into long-term contracts, customers may only be willing to provide acreage dedications to our assets rather than firm fee commitments. Acreage dedications typically do not require our customers to pay us unless they utilize our assets, and they could be vulnerable to challenge in bankruptcy proceedings.

To the extent we are unable to renew or replace our existing contracts on terms that are favorable to us or successfully manage the long-term nature and economic structure of our contract profile over time, our revenues and cash flows could decline and our ability to make quarterly cash dividends to our Class A shareholders could be materially and adversely affected.

We are exposed to the creditworthiness and performance of our customers, suppliers and contract counterparties, and any material nonpayment or nonperformance by one or more of these parties could adversely affect our financial condition, cash flows, and operating results.

Although we attempt to assess the creditworthiness of our customers, suppliers and contract counterparties, there can be no assurance that our assessments will be accurate or that there will not be a rapid or unanticipated deterioration in their creditworthiness, which may have an adverse impact on our business, results of operations, financial condition and ability to make quarterly cash dividends to our Class A shareholders. Our long-term firm fee contracts obligate our customers to pay demand charges regardless of whether they utilize our assets, except for certain circumstances outlined in applicable customer agreements. As a result, during the term of our long-term firm fee contracts and absent an event of force majeure, our revenues will generally depend on our customers' financial condition and their ability to pay rather than upon the extent to which our customers actually utilize our assets. Periods of price reduction and high volatility in the commodity markets could impact their ability to meet their financial obligations to us. Further, our contract counterparties may not perform or adhere to existing or future contractual arrangements. To the extent one or more of our contract counterparties is in financial distress or commences bankruptcy proceedings, contracts with these counterparties may be subject to renegotiation or rejection under applicable provisions of the United States Bankruptcy Code. Any material nonpayment or nonperformance by our contract counterparties due to inability or unwillingness to perform or adhere to contractual arrangements could have a material adverse impact on our business, results of operations, financial condition and ability to make quarterly cash dividends to our Class A shareholders.

For example, in May 2019, EM Energy Ohio, LLC, or EM Energy, and certain of its affiliates filed for bankruptcy protection. EM Energy had a firm transportation service agreement with Rockies Express for 50,000 Dth/d through January 5, 2032. Rockies Express and EM Energy have stipulated in the bankruptcy proceeding that the termination date of the firm transportation service agreement is June 13, 2019. Following the termination, Rockies Express made a drawing equal to the outstanding face amount on the letter of credit supporting EM Energy's obligations under the firm transportation service agreement and received approximately \$16.2 million in June 2019. While we intend to pursue our claim against the bankruptcy estate of EM Energy for damages of approximately \$89 million, we may ultimately not recover any of these damages in the bankruptcy litigation. Further, we will attempt to remarket the capacity resulting from the termination of EM Energy's firm transportation service agreement, but any new contracts may not provide the same level of revenue we received under the terminated agreement.

In addition, Ultra Resources, Inc., or Ultra, defaulted on its firm transportation service agreement with Rockies Express in 2016 for approximately 200,000 Dth/d through November 11, 2019, and as a result, Rockies Express filed a lawsuit seeking approximately \$303 million in damages and other relief. Approximately 13% of Rockies Express' revenue in 2015 was derived from the Ultra contract. In April 2016, Ultra filed for bankruptcy protection and in January 2017, Rockies Express and Ultra agreed to settle Rockies Express' claim against Ultra's bankruptcy estate. 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 service agreement with Rockies Express commencing December 1, 2019, for west-to-east service of 200,000 Dth/d at a rate of approximately \$0.37/Dth, or approximately \$26.8 million annually. Although the Ultra claim was ultimately settled, and on terms we view as favorable, other bankruptcy proceedings with a counterparty may not result in a favorable settlement for us. In September 2019, Ultra Petroleum Corp, the parent company of Ultra, announced it had entered into an amendment to its credit facility that, among things, established a reduced borrowing base of \$1.175 billion, automatically reduced the credit facility commitment to \$120 million in February 2020, eliminated all financial maintenance covenants and established maximum capital expenditures of \$65 million, \$10 million and \$5 million for the quarters ended September 30, 2019, December 31, 2019 and quarterly thereafter. In the same announcement, Ultra Petroleum Corp. also stated it was suspending drilling activity by the end of the September 2019 and it provided a preliminary outlook for 2020 assuming no

additional drilling next year. These changes in Ultra Petroleum Corp.'s liquidity and production could potentially affect Ultra's ability to make payments under its firm transportation service agreement that only recently commenced on December 1, 2019 and result in Ultra filing for bankruptcy protection.

The procedures and policies we use to manage our exposure to credit risk, such as credit analysis, credit monitoring and, in some cases, requiring credit support, cannot fully eliminate counterparty credit risks. In accordance with FERC regulations and our own internal credit policies, counterparties with investment grade credit ratings are deemed able to meet their financial obligations to us without requiring credit support in the form of a letter of credit, prepayment, guarantees or other forms of credit support. Although we may require credit support from our transportation customers we deem to not be creditworthy or upon a deterioration of the financial condition of an existing customer, some customers may not comply with such requirements, especially when experiencing financial distress. To the extent our procedures and policies prove to be inadequate or we are unable to obtain credit support, our financial position and results of operations may be negatively impacted.

Some of our counterparties may be highly leveraged or have limited financial resources and are subject to their own operating and regulatory risks. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with such parties. As seen with the decline and volatility in crude oil prices from the second half of 2014 through the first half of 2016 and in the second half of 2018, prices for crude oil and natural gas are subject to large fluctuations in response to changes in supply and demand, market uncertainty and a variety of other factors that are beyond our control. Such volatility in commodity prices might have an impact on many of our counterparties and their ability to borrow and obtain additional capital on attractive terms, which, in turn, could have a negative impact on their ability to meet their obligations to us.

In addition, in response to concerns related to climate change, there have been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds, promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuels. For example, officials in New York state and New York City have announced their intent to divest the state and city pension funds' holdings in fossil fuel companies, and the World Bank has announced that it will no longer finance upstream oil and gas after 2019, except in "exceptional circumstances." Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our customers' business activities, operations and costs of access to capital, which, in turn, could adversely impact their ability to meet their obligations to us.

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

We depend on certain key customers for a significant portion of our revenues and are exposed to credit risks of these customers. The loss of or material nonpayment or nonperformance by any of these key customers could adversely affect our cash flow and results of operations.

We rely on certain key customers for a portion of revenues. For example, for the year ended December 31, 2019, Continental Resources accounted for approximately 10% of our revenues on a consolidated basis. In addition, for the year ended December 31, 2019, approximately 45% of our consolidated revenues were represented by the top ten customers on our Pony Express System. We own a 75% membership interest in Rockies Express, which is not consolidated for financial reporting purposes. Approximately 16%, 16%, 13%, and 13% respectively, of Rockies Express' total revenues for the year ended December 31, 2019 were represented by Rockies Express' four largest non-affiliated shippers, and the firm contract with Rockies Express' largest non-affiliated shipper by total revenues expired in November 2019.

We may be unable to negotiate extensions or replacements of contracts with key customers on favorable terms. For additional detail, see "*If we are not able to renew or replace expiring customer contracts at favorable rates or on a long-term basis, our financial condition, results of operations, cash flows and ability to make quarterly cash dividends to our Class A shareholders will be adversely affected.*"

In addition, some of these key customers may experience financial problems that could have a significant effect on their creditworthiness. For example, Rockies Express terminated its contract with its third largest non-affiliated shipper by total 2015 revenue, Ultra, in March 2016. For more detail regarding Ultra, see "*We are exposed to the creditworthiness and performance of our customers, suppliers and contract counterparties, and any material nonpayment or nonperformance by one or more of these parties could adversely affect our financial condition, cash flows, and operating results.*"

Severe financial problems encountered by our customers could limit our ability to collect amounts owed to us, or to enforce performance of obligations under contractual arrangements. To the extent one or more of our key customers is in financial distress or commences bankruptcy proceedings, contracts with these customers may be subject to renegotiation or rejection under applicable provisions of the United States Bankruptcy Code. Additionally, many of our customers finance their activities through cash flow from operations, the incurrence of indebtedness or the issuance of equity. The combination of

reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under credit facilities and the lack of availability of debt or equity financing may result in a significant reduction of our customers' liquidity and limit their ability to make payments or perform on their obligations to us. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. The loss of all or even a portion of the contracted volumes of these key customers, as a result of competition, creditworthiness or otherwise, could have a material adverse effect on our business, cash flows, ability to make quarterly cash dividends to our Class A shareholders, the price of our Class A shares, our results of operations and ability to conduct our business.

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

Our ability to grow depends, in part, on our ability to make acquisitions that increase our cash generated from operations on a per share basis.

The acquisition component of our strategy is based, in part, on our expectation of ongoing divestitures of midstream energy assets by industry participants. Many factors could impair our ability to acquire additional midstream assets in the future. A material decrease in divestitures of midstream energy assets by industry participants would limit our opportunities for future acquisitions and could have a material adverse effect on our business, results of operations, financial condition and ability to make quarterly cash dividends to our Class A shareholders. Prior to February 7, 2018, Tallgrass Development was our primary source of acquisitions. Now that Tallgrass Development has divested its entire asset portfolio and merged out of existence, our growth through acquisitions will rely almost exclusively on buying assets or businesses from third parties.

Our future growth and ability to maintain or increase dividends will be limited if we are unable to make accretive acquisitions because, among other reasons, (i) we are unable to identify attractive acquisition opportunities, (ii) we are unable to negotiate acceptable purchase contracts, (iii) we are unable to obtain financing for these acquisitions on economically acceptable terms, (iv) we are outbid by competitors or (v) we are unable to obtain necessary governmental or third-party consents. Furthermore, even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations on a per share basis. For example, we completed a number of acquisitions in 2018 and 2019, including the acquisition of 100% of the outstanding membership interest of CES, an additional 25.01% membership interest in Rockies Express from Tallgrass Development, a 100% membership interest in NGL Water Solutions Bakken, LLC from NGL Energy Partners, a 51% membership interest in Pawnee Terminal from Zenith Energy, and a 38% membership interest in Deeprock North from Kinder Morgan. If certain risks or unanticipated liabilities were to arise, the desired benefits of these acquisition may not be fully realized and our future financial performance and results of operations could be negatively impacted.

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

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

If any acquisition eventually proves not to be accretive to our cash available for dividend per share, it could have a material adverse effect on our business, results of operations, financial condition and ability to make quarterly cash dividends to our Class A shareholders.

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

One of the ways we may grow our business is by constructing additions or modifications to our existing facilities. We also may construct new facilities, either near our existing operations or in new areas. Construction projects require significant amounts of capital and involve numerous regulatory, environmental, political, legal and operational uncertainties, many of which are beyond our control. We may be unable to complete announced construction projects on schedule, at the budgeted cost, or at all, which could have a material adverse effect on our business and results of operations. For example, we announced

the Cheyenne Hub Enhancement Project and the Cheyenne Connector Pipeline in September 2017 and submitted applications for the FERC's issuance of a certificate of public convenience and necessity pursuant to section 7(c) of the NGA with respect to these projects in March 2018. However, the FERC did not issue an order approving the applications until September 2019. As a result, the expected in-service date of the Cheyenne Hub Enhancement Project and the Cheyenne Connector Pipeline was delayed to the first half of 2020. In addition, in June 2014, Michels Corporation, or Michels, filed a complaint and request for relief against Rockies Express as a result of work performed by Michels to construct the Seneca Lateral Pipeline in Ohio. Michels sought unspecified damages from Rockies Express and asserted claims of breach of contract, negligent misrepresentation, unjust enrichment and quantum meruit, and also filed notices of Mechanic's Liens in Monroe and Noble Counties, asserting \$24.2 million as the amount due. In February 2017, Rockies Express and Michels resolved the claims brought by Michels in exchange for a \$10 million cash payment by Rockies Express.

Although we evaluate and monitor each capital spending project and try to anticipate difficulties that may arise, such delays or cost increases may arise as a result of factors that are beyond our control, including:

- denial or delay in issuing requisite regulatory approvals and/or permits, which for many of our projects includes a requirement to obtain a certificate from the FERC authorizing the project before construction can commence;
- unplanned increases in the cost of construction materials or labor;
- disruptions in transportation of modular components and/or construction materials;
- adverse weather conditions, natural disasters, or other events (such as equipment malfunctions, explosions, fires, releases) out of our control that result in construction delays;
- shortages of sufficiently skilled labor, or labor disagreements resulting in unplanned work stoppages;
- changes in market conditions impacting long lead-time projects;
- market-related increases in a project's debt or equity financing costs; and
- nonperformance by, or disputes with, vendors, suppliers, contractors, or sub-contractors involved with a project.

These projects also involve numerous economic uncertainties and the cash flow generated from these projects may not meet expectations or project estimates. Moreover, we may not receive any material increase in operating cash flow from a project for some time or at all. For instance, we began incurring construction costs for the Iron Horse Pipeline, the Cheyenne Connector Pipeline and the Cheyenne Hub Enhancement Project shortly after these projects were announced. However, we do not receive any increases in cash flow from these projects until such projects are completed and placed in-service.

The project specifications and expectations regarding project cost, timing, asset performance, investment returns and other matters usually rely in part on the expertise of third parties such as engineers, technical experts and construction contractors. These estimates may prove to be inaccurate because of numerous operational, technological, economic and other uncertainties. We also rely in part on estimates from producers regarding the timing and volume of anticipated natural gas and crude oil production. Production estimates are subject to numerous uncertainties, nearly all of which are beyond our control. These estimates may prove to be inaccurate, and new facilities may not attract sufficient volumes to achieve our expected cash flow and investment return.

If we are unable to obtain needed capital or financing on satisfactory terms our ability to make quarterly cash dividends may be diminished or our financial leverage could increase.

In order to expand our asset base through acquisitions or capital projects, we may need to make expansion capital expenditures. If we do not make sufficient or effective expansion capital expenditures, we will be unable to expand our business operations and may be unable to maintain or raise the level of our quarterly cash dividends. We could be required to use cash from our operations or incur borrowings or sell additional Class A shares or other limited partner interests in order to fund our expansion capital expenditures. Using cash from operations will reduce cash available for dividends to our Class A shareholders. Our ability to obtain bank financing or to access the capital markets for future equity or debt offerings may be limited by our financial condition at the time of any such financing or offering as well as the covenants in our debt agreements, general economic conditions and contingencies and uncertainties that are beyond our control. For example, in response to concerns related to climate change, there have been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds, promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuels. Such efforts directed at midstream companies such as ours could adversely impact our future access to capital markets. In addition, the limited partnership structure for public companies has been criticized by investors as lacking transparency and accountability as compared to publicly traded corporations, which has reduced demand for investments in publicly traded limited partnerships.

Even if we are successful in obtaining funds for expansion capital expenditures through equity or debt financings, the terms thereof could limit our ability to pay quarterly cash dividends to our Class A shareholders. In addition, incurring

additional debt may significantly increase our interest expense and financial leverage, and issuing additional limited partner interests may result in significant dilution of Class A shareholders and increase the aggregate amount of cash required to maintain the then-current dividend rate, which could materially decrease our ability to pay quarterly cash dividends at the then-current dividend rate. We do not currently have any commitment with our general partner or other affiliates, including the Sponsor Entities, for them to provide any direct or indirect financial assistance to us.

The Throughput and Deficiency Agreements for the Pony Express System and some of our service agreements with respect to our water business services contain provisions that can reduce the cash flow stability that the agreements were designed to achieve.

The Throughput and Deficiency Agreements, or TDAs, for the Pony Express System and some of our service agreements with respect to our water services business are firm fee contracts with minimum volume commitments that are designed to generate stable cash flows and minimize direct commodity price risk. Under these minimum volume commitments, our customers agree to ship a minimum volume of crude oil or to have a minimum volume of water serviced, as the case may be, over certain periods during the term of the applicable agreement.

If a customer's actual throughput volumes or volumes serviced are less than its minimum volume commitment for the applicable period, it must make a deficiency payment at the end of the applicable period based upon the difference between the minimum volume commitment and the actual amounts serviced. A customer may apply any deficiency payments it makes as a credit against payment for volumes transported or serviced by us in excess of its minimum volume commitment in future periods. Upon termination of the Pony Express TDAs, customers may continue to use any remaining deficiency credits against any volumes serviced by us for a period of six months following termination, even though such customers may no longer have a minimum volume commitment.

To the extent that a customer's actual throughput volumes or volumes serviced are above its minimum volume commitment for the applicable period, the customer may use the excess volumes to credit against future deficiency payments in subsequent periods. As of December 31, 2019, Pony Express had a cumulative net deficiency balance of \$106.9 million and a cumulative shipper incremental balance of \$6.0 million.

Some or all of these provisions can apply in combination with one another. As a result, in the future we may not receive any cash payments for volumes shipped or serviced by us, and we may not receive deficiency payments as a result of excess volumes shipped in prior periods. This would result in reduced revenue and cash flows to us and could have a material adverse effect on our ability to make quarterly cash dividends to our Class A shareholders.

We may not be able to compete effectively in our midstream services activities and our business is subject to the risk of a capacity overbuild of midstream energy infrastructure in the areas where we operate.

We face competition in all aspects of our business and may not be able to compete effectively against our competitors. In general, competition comes from a wide variety of players in a wide variety of contexts, including new entrants and existing players and in connection with day-to-day business, expansion capital projects, acquisitions and joint venture activities. Some of our competitors have capital resources greater than ours and control greater supplies of crude oil, natural gas or NGLs.

Our ability to renew or replace our existing contracts at rates sufficient to maintain current revenues and current cash flows could be adversely affected by the activities of our competitors. Some of our competitors have assets in closer proximity to certain hydrocarbon supplies and have available idle capacity in existing assets that may require no or minimal capital investments for use. For example, several pipelines access many of the same basins as our assets and provide transport to customers in the Rocky Mountain, Appalachian Mountain and Midwest regions of the United States, such as the Dakota Access Pipeline, Saddlehorn-Grand Mesa Pipeline and White Cliffs Pipeline that compete with the Pony Express Pipeline. Pony Express also competes with rail facilities, which can provide more delivery optionality to crude oil producers and marketers looking to capitalize on basis differentials between two primary crude oil benchmarks (West Texas Intermediate Crude and Brent Crude). Furthermore, the Sponsor Entities and their affiliates and owners are not limited in their ability to compete with us.

Our competitors may expand or construct new midstream services assets that would create additional competition for the services we provide to our customers, or our customers may develop their own facilities in lieu of using ours. A significant driver of competition in some of the markets where we operate (including, for example, the Rocky Mountain and Appalachian Mountain regions) has been the rapid development of new midstream energy infrastructure capacity in recent years. As a result, we are exposed to the risk that the areas in which we operate become overbuilt, resulting in an excess of midstream energy infrastructure capacity. For example, Phillips 66 and Bridger Pipeline LLC announced in June 2019 that they had formed a 50/50 joint venture to construct the Liberty Pipeline. Per the announcement, the Liberty Pipeline would consist of a 24-inch pipeline to provide crude oil transportation service from the Rockies and Bakken production areas to Cushing, Oklahoma, with a targeted initial service date as early as the first quarter of 2021. Once constructed, the Liberty Pipeline will directly compete with the Pony Express Pipeline. If we experience a significant capacity overbuild in one or more of the areas where we operate,

it could have a significant adverse impact on our financial position, cash flows and ability to maintain or increase dividends to our Class A shareholders. In particular, our competitors in these areas could substantially decrease the prices at which they offer their services, and we may be unable to compete effectively without also substantially lowering the price for our services. This could materially impair our cash flows and ability to make quarterly cash dividends to our Class A shareholders.

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

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

Certain of the contracts on the Pony Express System contain most favored nations rights, limiting flexibility to offer certain capacity to new shippers.

As of December 31, 2019, approximately 22% of the available contractible capacity on the Pony Express System is subject to contracts that contain most favored nations rights, or MFNs, and additional contracts on the Pony Express System that begin service in May 2020 also contain MFNs. The MFNs grant a shipper the right to a rate reduction in certain instances, which effectively limits our flexibility in negotiating rates for some of the services with other shippers on the Pony Express System to avoid triggering the MFNs. Further, if we do trigger an MFN, the revenue generated by Pony Express from these contracts would be reduced, which could have a material adverse effect on our revenues, cash flow, results of operations, and our ability to make quarterly cash dividends to our Class A shareholders.

If third-party pipelines or other facilities interconnected to our systems become partially or fully unavailable, if the volumes we transport do not meet the quality requirements of such pipelines or facilities, or if claims are made against us for events that occur downstream of our interconnection with third-party facilities, our revenues and our ability to make quarterly cash dividends to our Class A shareholders could be adversely affected.

Our assets typically connect to other pipelines or facilities owned, leased and/or operated by unaffiliated third parties, such as ONEOK Bakken Pipeline, L.L.C., Whiting Petroleum, and others. For example, our Pony Express System connects to upstream joint tariff pipelines, including the Belle Fourche Pipeline owned by the True Companies (which also own and operate the Bridger Pipeline upstream of the Belle Fourche Pipeline) and the Double H Pipeline owned by Kinder Morgan, which are responsible for delivering a substantial portion of the crude oil for transportation on the Pony Express System. In addition, part of the crude oil we transport on the Pony Express System is either stored in crude oil tanks located on, or pumped over to downstream pipelines that interconnect through, the Cushing Terminal, which we do not operate.

The continuing operation of such third-party facilities and other midstream facilities is not within our control. These pipelines, plants and other midstream facilities may become unavailable to us for any number of reasons, including because of testing, turnarounds, line repair, extended unscheduled maintenance, reduced operating pressure, lack of operating capacity, regulatory requirements, conversion to another form of commodity transportation service, cessation of operations, curtailments of receipt or deliveries due to insufficient capacity or because of damage from weather events or other operational hazards. For example, the operations of the Bridger Pipeline's Poplar System were down for approximately five months during the first half of 2015 due to a pipeline release. Bridger declared a force majeure as a result of this event and temporarily lacked the capacity to make up volumes on other lines that directly or indirectly deliver crude oil into designated origin points on the Pony Express System or the Belle Fourche Pipeline. The largest committed shipper on the Pony Express System also declared a force majeure as a result of this incident.

In addition, our interconnection with third-party facilities may result in claims being made against us for events that occur downstream of our pipelines. For example, TIGT was named as a defendant in a lawsuit for damages arising from a gas leak and home explosion that occurred in June 2014 in Finney County, Kansas. Although TIGT did not directly distribute natural gas to the home in question, the plaintiffs nonetheless alleged that TIGT committed torts and otherwise violated federal safety laws. TIGT ultimately settled such claims in March 2019 pursuant to a confidential settlement. We could be subject to similar claims in the future.

If the costs to us to access and transport on these third-party pipelines or any alternative pipelines significantly increase, if any of these pipelines or other midstream facilities become unable to receive, transport, store or process products from our assets, if the volumes we transport or process do not meet the quality requirements of such pipelines or facilities, or if claims are made against us for events that occur downstream of our interconnection with third-party facilities, our revenues and our ability to make quarterly cash dividends to our Class A shareholders could be adversely affected.

The lack of diversification of our assets and geographic locations could adversely affect our ability to make quarterly cash dividends to our Class A shareholders.

We rely on revenues generated from our assets, which are primarily located in the Rocky Mountain, Appalachian Mountain and Midwest regions of the United States. Revenues on our assets primarily depend on exploration and production activities of our customers located in these regions. Due to our lack of diversification in assets and geographic location, an adverse development in these businesses or our customers' areas of operations, including adverse developments due to catastrophic events, weather, regulatory action and decreases in supply or demand for hydrocarbons, could have a significantly greater impact on our results of operations and cash available for dividends to our Class A shareholders than if we maintained more diverse assets and locations.

For example, our water business services are provided through a limited number of assets with a relatively high concentration in Weld County, Colorado. Thus, the growth and profitability of our water business services will be especially vulnerable to conditions and fluctuations in the local Weld County economy and subject to changes in local government regulations and priorities. In addition, a number of our other assets are also located in Colorado. Certain interest groups in Colorado generally opposed to the development of oil, natural gas and NGLs, and hydraulic fracturing in particular, have from time to time advanced various options for ballot initiatives aimed at significantly limiting or preventing the development of oil, natural gas and NGLs. For example, a Colorado ballot initiative, Proposition 112, would have substantially increased setback distances for various upstream activities, thereby substantially restricting new oil and natural gas development in the state. Although Proposition 112 was defeated in the November 2018 elections, similar efforts in Colorado, if passed, could restrict oil and natural gas development in the future which could result in a reduction in demand for our services.

In April 2019, the Colorado state legislature approved and the Colorado governor signed into law, Senate Bill 19-181, which reforms exploration and production activities by the oil and gas industry in the state including, among other things, revising the mission of the Colorado Oil and Gas Conservation Commission, or COGCC, from fostering energy development in the state to instead focusing on regulating the industry in a manner that is protective of public health and safety and the environment, as well as authorizing cities and counties to regulate oil and gas operations within their jurisdiction as they do other development. The COGCC has begun the process of proposing new and amended rules at the state level pursuant to Senate Bill 19-181. The COGCC held hearings in late 2019 and has planned additional hearings and anticipated draft rule proposals in 2020. Some local communities have adopted additional restrictions for oil and gas activities pursuant to Senate Bill 19-181, such as requiring greater setbacks, and other groups have sought a cessation of permit issuances entirely until the COGCC publishes new rules in keeping with Senate Bill 19-181. While the ultimate impact of this new law is currently unknown, this law or passage or enactment of other similar legislation could have a material adverse effect on our customers in the state of Colorado, which could reduce demand for our pipeline services.

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

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

In order to obtain permits and renewals of permits and other approvals in the future, we may be required to prepare and present data to governmental authorities pertaining to the potential adverse impact that any proposed activities may have on the environment, individually or in the aggregate, including on public and Indian lands. Certain approval procedures may require preparation of archaeological surveys, endangered species studies and other studies to assess the environmental impact of new sites or the expansion of existing sites. Compliance with these regulatory requirements is expensive and significantly lengthens the time needed to develop a site or pipeline alignment. Also, obtaining or renewing required permits or other approvals is sometimes delayed or prevented due to community opposition and other factors beyond our control. For example, in connection with the development and construction of the Cheyenne Connector Pipeline, we experienced delays before ultimately obtaining the land use permit from Weld County, Colorado when certain affected landowners raised objections to our project.

The denial of a permit or other approval essential to our operations or the imposition of restrictive conditions with which it is not practicable or feasible to comply could impair or prevent our ability to develop or expand a property or right-of-way. Significant opposition to a permit or other approval by neighboring property owners, members of the public or non-governmental organizations, or other third parties or delay in the environmental review and permitting process also could impair or delay our ability to develop or expand a property or right-of-way. New legal requirements, including those related to the protection of the environment, could be adopted at the federal, state and local levels that could materially adversely affect

our operations, our cost structure or our customers' ability to use our services. Such current or future regulations could have a material adverse effect on our business and we may not be able to obtain or renew permits or other approvals in the future.

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

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

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

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

Our success depends on the supply and demand for natural gas and crude oil.

The success of our business is in many ways impacted by the supply and demand for natural gas and crude oil. For example, our business can be negatively impacted by sustained downturns in supply and demand for natural gas and crude oil in the markets that we and our customers serve, including reductions in our ability to renew contracts on favorable terms and to construct new infrastructure. Further, a portion of the demand for our water business services depends substantially on the level of expenditures by the oil and gas industry for the exploration, development and production of oil and natural gas reserves. These expenditures are generally dependent on the industry's view of future oil and natural gas prices and are sensitive to the industry's view of future economic growth and the resulting impact on demand for oil and natural gas. Declines, as well as anticipated declines, in oil and gas prices could also result in project modifications, delays or cancellations, general business disruptions, and delays in, or nonpayment of, amounts that are owed to us. These effects could have a material adverse effect on our financial condition, results of operations and cash flows.

One of the major factors that will impact natural gas demand will be the potential growth of the demand for natural gas in the power generation market, particularly driven by the speed and level of existing coal-fired power generation that is replaced with natural gas-fired power generation rather than alternative energy sources. One of the major factors impacting domestic natural gas and crude oil supplies has been the significant growth in unconventional sources such as shale plays and the continued progression of hydraulic fracturing technology. The supply and demand for natural gas and crude oil, and therefore the future rate of growth of our business, depends on these and many other factors outside of our control, including, but not limited to:

- adverse changes in domestic laws and regulations;
- adoption of various energy efficiency and conservation measures;
- adverse changes in general global economic conditions;
- technological advancements that may drive further increases in production and reduction in costs of developing crude oil and natural gas shale plays;
- the price and availability of other forms of energy, including alternative energy which may benefit from government subsidies;
- prices for natural gas, crude oil and NGLs;
- decisions of the members of the Organization of the Petroleum Exporting Countries, or OPEC, regarding price and production controls;
- increased costs to explore for, develop, produce, gather, process and transport natural gas or crude oil;
- weather conditions, seasonal trends and hurricane disruptions;
- the nature and extent of, and changes in, governmental regulation, for example regulation of GHGs and hydraulic fracturing;

- perceptions of customers on the availability and price volatility of our services and natural gas and crude oil prices, particularly customers' perceptions on the volatility of natural gas and crude oil prices over the long-term;
- capacity and transportation service into, or out of, our markets; and
- petrochemical demand for NGLs.

The oil and gas industry historically has experienced periodic downturns. For example, from the second half of 2014 through the first half of 2016, the oil and gas industry experienced a sustained period of decline and volatility in natural gas and crude oil prices. Throughout 2019, the industry again experienced sustained lower natural gas prices. Such volatility and decline in oil and/or natural gas prices might have an impact on our counterparties and their drilling plans. For example, in September 2019, Ultra Petroleum Corp, the parent company of Ultra, stated it was suspending drilling activity by the end of the September 2019 and it provided a preliminary outlook for 2020 assuming no additional drilling next year. Any prolonged downturns in the oil and gas industry could result in a reduction in demand for our services and could adversely affect our financial condition, results of operations and cash flows.

Any significant decrease in available supplies of hydrocarbons in our areas of operation, or redirection of existing hydrocarbon supplies to other markets, could adversely affect our business and operating results. Persistent low commodity prices could result in lower throughput volumes and reduced cash flows.

Our business is dependent on the continued availability of natural gas and crude oil production and reserves. Production from existing wells and natural gas and crude oil supply basins with access to our assets will naturally decline over time. The amount of natural gas and crude oil reserves underlying these wells may also be less than anticipated, and the rate at which production from these reserves declines may be greater than anticipated. Accordingly, to maintain or increase the contracted capacity and/or the volume of products utilizing our assets, our customers must continually obtain adequate supplies of natural gas and crude oil.

However, the development of additional natural gas and crude oil reserves requires significant capital expenditures by others for exploration and development drilling and the installation of production, storage, transportation and other facilities that permit natural gas and crude oil to be produced and products delivered to our facilities. In addition, low prices for natural gas and crude oil, regulatory limitations, including environmental regulations, or the lack of available capital for these projects could have a material adverse effect on the development and production of additional reserves, as well as storage, pipeline transportation, and import and export of natural gas and crude oil supplies. The volatility and sustained lower prices for crude oil and refined products from the second half of 2014 through the first half of 2016, and for natural gas throughout 2019, led to a decline in drilling activity, production and refining of these hydrocarbons, and import levels in these areas. For example, in response to this volatility and lower prices, a number of producers in our areas of operation significantly reduced their capital budgets and drilling plans in 2015 through 2017. Similarly, in September 2019, Ultra Petroleum Corp, the parent company of Ultra, stated it was suspending drilling activity by the end of the September 2019 and it provided a preliminary outlook for 2020 assuming no additional drilling next year. These changes in Ultra Petroleum Corp's liquidity and production could potentially affect Ultra's ability to make payments under its firm transportation service agreement that only recently commenced on December 1, 2019 and result in Ultra filing for bankruptcy protection. In addition, production may fluctuate for other reasons, including, for example, in the case of crude oil, the extent to which the members of OPEC abide by agreements regarding production controls. Furthermore, competition for natural gas and crude oil supplies to serve other markets could reduce the amount of natural gas and crude oil supply available for our customers. Accordingly, to maintain or increase the contracted capacity and/or the volume of products utilizing our assets, our customers must compete with others to obtain adequate supplies of natural gas and crude oil.

If new supplies of natural gas and crude oil are not obtained to replace the natural decline in volumes from existing supply basins, if natural gas and crude oil supplies are diverted to serve other markets, if environmental regulations restrict new natural gas and crude oil drilling or if OPEC does not maintain production controls, the overall demand for services on our systems will likely decline, which could have a material adverse effect on our ability to renew or replace our current customer contracts when they expire and on our business, financial condition, results of operations and ability to make quarterly cash dividends to our Class A shareholders.

Our natural gas, crude oil and liquids operations, including the rates charged on our natural gas and crude oil pipeline systems, are subject to extensive regulation by federal, state and local regulatory authorities, which could have a material adverse effect on our business, financial condition, and results of operations.

We provide open-access interstate transportation service on our interstate natural gas transportation systems pursuant to tariffs approved by the FERC. Our interstate natural gas transportation and storage operations are regulated by the FERC, under the NGA, the NGPA, and the EPCA 2005. The Rockies Express Pipeline, the TIGT System and the Trailblazer Pipeline each operate under a tariff approved by the FERC that establishes rates and terms and conditions of service to our customers. The rates and terms of service on the Pony Express System, the PRE Pipeline and the Iron Horse Pipeline are subject to regulation

by the FERC under the ICA, and the Energy Policy Act of 1992. We provide interstate crude oil transportation service on the Pony Express System, the PRE Pipeline and the Iron Horse Pipeline pursuant to tariffs on file with the FERC. Our NGL pipeline that interconnects with Overland Pass Pipeline is leased to a third party that has obtained a FERC waiver from the tariff, filing and reporting requirements of the ICA, and our NGL pipeline that interconnects with ONEOK's Bakken NGL Pipeline is leased to a third party that is obligated to operate the leased pipeline in conformance with the ICA as a FERC-regulated NGL pipeline.

Generally, the FERC's authority over natural gas facilities extends to:

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

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

- rates, rules and regulations of service;
- the form of tariffs governing rates and service;
- the maintenance of accounts and records; and
- depreciation and amortization policies.

Interstate natural gas and crude oil pipelines subject to the jurisdiction of the FERC may not charge rates or impose terms and conditions of service that, upon review by the FERC, are found to be unjust, unreasonable, unduly discriminatory, or preferential.

Pursuant to the NGA, existing interstate natural gas transportation and storage rates and terms and conditions of service may be challenged by complaint and are subject to prospective change by the FERC. Additionally, rate changes and changes to terms and conditions of service proposed by a regulated natural gas interstate pipeline may be protested and such changes can be delayed and may ultimately be rejected by the FERC. The FERC may also initiate reviews of our rates. We currently hold authority from the FERC to charge and collect (i) "recourse rates" (i.e., the maximum cost-based rates an interstate natural gas pipeline may charge for its services under its tariff); (ii) "discount rates" (i.e., rates offered by the natural gas pipeline to shippers at discounts vis-à-vis the recourse rates and that fall within the cost-based maximum and minimum rate levels set forth in the natural gas pipeline's tariff); and (iii) "negotiated rates" (i.e., rates negotiated and agreed to by the pipeline and the shipper for the contract term that may fall within or outside of the cost-based maximum and minimum rate levels set forth in the tariff, and which are individually filed with the FERC for review and acceptance). When capacity is available and offered for sale, the rates (which include reservation, commodity, surcharges, and fixed fuel and lost and unaccounted for charges) at which such capacity is sold are subject to regulatory approval and oversight. We cannot guarantee that any new or existing tariff rate for service on the Rockies Express Pipeline, the TIGT System or Trailblazer Pipeline would not be rejected or modified by the FERC, or subjected to refunds. Any successful challenge by a regulator or shipper in any of these matters could have a material adverse effect on our business, financial condition and results of operations.

In 2019, we entered into settlements with our customers on the TIGT System and the Trailblazer Pipeline. As a result of these settlements, the rates we can charge on the TIGT System are expected to remain in place through May 31, 2023, and, subject to the approval of the settlement by the FERC, the rates we can charge on the Trailblazer Pipeline are expected to remain in place through December 31, 2025. In the event the assumptions relied upon during settlement negotiations were incorrect or the actual costs incurred to operate these pipelines increase, our cash flows and results of operations could be adversely affected.

Pursuant to the ICA, existing interstate crude oil transportation rates and terms and conditions of service may be challenged by complaint. A successful complainant is entitled to reparations going back two years from the date of the complaint as well as forward reparations from the date of the complaint until a new rate or policy is put in place. Additionally,

rate changes and changes to terms and conditions of service proposed by a regulated interstate crude oil pipeline may be protested and such changes can be suspended for up to seven months and may ultimately be rejected by the FERC. We currently have three different rate types across our systems. The first are contract rates, which means they are contractually agreed to and given in exchange for either commitments to ship on the pipeline or acreage dedications ("Contract Rates"). Contract Rates will generally be honored by the FERC during the term of the contracts. Contract Rates may be changed annually based on the terms of the contract. The second are indexed rates, which means they may be increased or decreased at any time provided they do not exceed the index ceiling ("Indexed Rates"). The index ceiling is calculated yearly by applying the FERC-approved inflationary adjustment, which may be positive or negative. These rates can be challenged on a cost-of-service basis. The third are volume incentive rates, which reflect a discount to the Indexed Rates and are available to all shippers without a contractual commitment to ship on the pipeline ("Volume Incentive Rates"). These discounts are discretionary and not challengeable on a cost-of-service basis; however, should Pony Express' Indexed Rates be lowered due to a cost-of-service challenge, the Volume Incentive Rates would have to be reduced if they are no longer below the Indexed Rates. Interstate crude oil pipelines typically must reserve at least ten percent of their capacity for walk-up shippers, i.e., shippers with no contractual commitment to ship.

We cannot guarantee that any new or existing tariff rate for service on the Pony Express System, the PRE Pipeline, or the Iron Horse Pipeline would not be rejected or modified by the FERC, or subjected to refunds or reparations. While the FERC regulates rates and terms and conditions of service for transportation of crude oil in interstate commerce by pipeline, state agencies may also regulate facilities (including construction, acquisition, disposition, financing, and abandonment), rates, and terms and conditions of service for crude oil pipeline transportation in intrastate commerce. Any successful challenge by a regulator or shipper in any of these matters could have a material adverse effect on our business, financial condition and results of operations.

Pony Express Pipeline's tariff rates may not always be eligible for increases to reflect a FERC index adjustment. In addition, the FERC may modify how it determines eligibility for applying the FERC index adjustment. For example, on November 2, 2016, the FERC issued an Advanced Notice of Proposed Rulemaking, under which the FERC is proposing changes to its policies regarding the eligibility for a rate increase under indexing, based on specific pipelines' earnings or their specific changes to costs. The FERC's Advanced Notice of Proposed Rulemaking does not propose specific regulations, and may be followed by a Notice of Proposed Rulemaking proposing specific regulations or a Policy Statement announcing new or changed policies. This proceeding is pending before the FERC.

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

For example, in March 2018 we submitted applications to the FERC pursuant to section 7(c) of the NGA for a certificate of public convenience and necessity authorizing the Cheyenne Hub Enhancement Project and the Cheyenne Connector Pipeline. However, the FERC did not issue an order approving the applications until September 2019. As a result, the expected in-service date of the Cheyenne Hub Enhancement Project and the Cheyenne Connector Pipeline was delayed to the first half of 2020.

The FERC has the authority to conduct audits of regulated entities to assess compliance with FERC regulations and policies. The FERC also conducts audits to verify that the websites of interstate natural gas pipelines accurately provide information on the operations and availability of services on the pipeline. FERC regulations also require entities providing interstate natural gas and crude oil transportation services to comply with uniform terms and conditions for service, as set forth in publicly available tariffs or, as it concerns natural gas facilities, agreements for transportation and storage services executed between interstate pipelines and their customers. Natural gas transportation service agreements are generally required to conform, in all material respects, with the standard form of service agreements set forth in the natural gas pipeline's FERC-

approved tariff. The pipeline and a customer may choose to enter into a non-conforming service agreement so long as the agreement is filed with, and accepted by, the FERC. In the event that the FERC finds that a natural gas transportation agreement, in whole or part, is materially non-conforming, the FERC could reject the agreement or require us to modify the agreement, or alternatively require us to modify our tariff so that the non-conforming provisions are generally available to all customers. Transportation agreements entered into with crude oil shippers are generally not subject to FERC regulation or required to be available for FERC or public review, but the rates and terms and services provided to similarly situated shippers may not be unduly discriminatory or preferential.

The FERC has promulgated rules and policies covering many aspects of our natural gas pipeline business, including regulations that require us to provide firm and interruptible transportation service on an open access basis that is not unduly discriminatory or preferential, provide internet access to current information about our available pipeline capacity and other relevant transmission information, and permit pipeline shippers to release contracted transportation and storage capacity to other shippers, thereby creating secondary markets for such services. FERC regulations also prevent interstate natural gas pipelines from sharing customer information with marketing affiliates, and restrict how interstate natural gas pipelines share transportation information with marketing affiliates. FERC regulations require that certain transmission function personnel of interstate natural gas pipelines function independently of personnel engaged in natural gas marketing functions. Crude oil pipelines subject to the ICA must comply with FERC regulations that require the pipeline to act as a common carrier and not engage in undue discrimination or preferential treatment with respect to shippers. The ICA also prevents crude oil and NGL pipelines from disclosing certain shipper information without the shipper's consent.

FERC policies also govern how interstate natural gas pipelines respond to interconnection requests from third party facilities, including other pipelines. Generally, an interstate natural gas pipeline must grant an interconnection request upon the satisfaction of several conditions. As a consequence, an interstate natural gas pipeline faces the risk that an interconnecting third-party pipeline may pose a risk of additional competition to serve a particular market or customer. Failure to comply with applicable provisions of the NGA, NGPA, EPCA 2005 and certain other laws, as well as with the regulations, rules, orders, restrictions and conditions associated with these laws, could result in the imposition of administrative and criminal remedies, including without limitation, revocation of certain authorities, disgorgement of ill-gotten gains, and civil penalties of more than \$1 million per day, per violation. Violations of the ICA, the Energy Policy Act of 1992, or regulations and orders promulgated by the FERC are also subject to administrative and criminal penalties and remedies, including forfeiture and individual liability.

In addition, new laws or regulations or different interpretations of existing laws or regulations applicable to our pipeline systems or midstream facilities could have a material adverse effect on our business, financial condition, results of operations and prospects. For example, on November 22, 2017, in FERC Docket No. OR17-2-000, the FERC issued an Order on Petition for Declaratory Order addressing whether certain specific hypothetical transactions between a petroleum liquids pipeline and its marketing affiliate proposed by the petitioner, Magellan Midstream Partners, L.P., would violate the requirements of the ICA or the FERC's regulations and policies. The FERC concluded that certain transactions proposed by the petitioner could be inconsistent with the ICA and the FERC's policies. Various market participants filed requests for clarification or, in the alternative, rehearing of the November 22, 2017 declaratory order. On January 22, 2018, the FERC issued an order granting rehearing for further consideration, which afforded the FERC additional time to consider and rule on the pending clarification/rehearing requests. The outcome of this proceeding and any related proceeding(s) may require us to modify the business practices between our petroleum liquids pipelines regulated by the FERC and our affiliated marketer, Stanchion. To the extent the foregoing proceedings result in substantial new restrictions on the transactions between petroleum liquids pipelines and their affiliated shippers, the business activities of Stanchion could be affected.

The FERC's treatment of income taxes could affect the rates charged on our natural gas and crude oil pipeline systems which could adversely affect our business, results of operations, financial condition and ability to make quarterly cash dividends to our Class A shareholders.

The FERC has historically permitted regulated interstate crude oil and natural gas pipelines to include an income tax allowance in their cost of service used to calculate cost-based transportation rates. The allowance is intended to reflect the actual or potential tax liability attributable to the regulated entity's operating income, regardless of the form of ownership. On July 1, 2016, in *United Airlines, Inc. v FERC*, the United States Court of Appeals for the D.C. Circuit vacated a pair of FERC orders to the extent they permitted an interstate refined petroleum products pipeline owned by a Master Limited Partnership ("MLP") to include an income tax allowance in its cost-of-service rates. The D.C. Circuit held that the FERC had failed to demonstrate that the inclusion of both an income tax allowance in the pipeline's rates and a return on equity determined using a discounted cash flow methodology would not lead to a double-recovery of income tax costs for a pipeline organized as an MLP.

Following the D.C. Circuit's decision, the FERC issued its Revised Policy Statement on Treatment of Income Taxes in Docket No. PL17-1-000 on March 15, 2018 which eliminates the recovery of an income tax allowance by MLP crude oil and natural gas pipelines in cost-of-service-based rates. The FERC directed MLP crude oil pipelines to reflect the elimination of the income tax allowance in their Form No. 6, page 700 reporting and stated that it will incorporate the effects of this Revised Policy on industry-wide crude oil pipeline costs in the 2020 five-year review of the pipeline index level that pipelines with rates

subject to annexing apply annually to adjust the rates. The FERC also stated that it would address income tax allowances for other "pass-through" entities that are not MLPs in future proceedings.

While we are not an MLP, our ownership of our FERC-regulated pipelines is held directly and indirectly by "pass-through" entities. The FERC could determine to apply the elimination of the income tax allowance to such "pass-through" entities. To the extent that we charge cost-of-service based rates, those rates could be affected by the elimination of the income tax allowance if our rates are subject to complaint or challenge raised by shippers or by the FERC acting on its own initiative, or if we propose new cost-of-service rates or changes to our existing rates. In such instances, it is possible that certain tariff rates could be reduced, which could adversely affect our financial position, results of operations and ability to make quarterly cash dividends to our Class A shareholders.

On December 22, 2017, federal legislation known as the "Tax Cuts and Jobs Act" was enacted, which made various changes to the United States tax laws, including reducing the highest marginal U.S. federal corporate income tax rate from 35% to a flat rate of 21% for tax years beginning after December 31, 2017, adjusting the individual income tax brackets, and establishing limited deductions for certain income from "pass-through" entities. In late 2018, Rockies Express and TIGT each submitted one-time informational filings in compliance with Order No. 849, which required interstate natural gas pipelines to make a one-time informational filing on the rate effect of the changes in tax laws and policy following the Tax Cuts and Jobs Act and the FERC's changes to its Income Tax Policy Statement. FERC determined that no action was required on Rockies Express' filing to adjust its rates in respect of the tax changes. In connection with FERC's approval of the TIGT pre-filing rate settlement, FERC also took no action in respect of the tax changes. The effects of the corporate income tax rate reduction will be considered by FERC in 2020 in the five-year review of the pipeline index level.

The outcome of these proceedings could affect the rates charged on our natural gas and crude oil pipeline systems which could have a material adverse effect on our business, results of operations, financial condition and ability to make quarterly cash dividends to our Class A shareholders.

We are subject to numerous hazards and operational risks.

Our operations are subject to all the risks and hazards typically associated with transportation, storage, terminalling, processing, gathering and disposing of hydrocarbons and water. These operating risks include, but are not limited to:

- damage to pipelines, facilities, equipment and surrounding properties caused by hurricanes, earthquakes, tornadoes, floods, fires or other adverse weather conditions and other natural disasters and acts of terrorism;
- inadvertent damage from construction, vehicles, farm and utility equipment;
- uncontrolled releases of crude oil, natural gas and other hydrocarbons or hazardous materials, including water from hydraulic fracturing;
- leaks, migrations or losses of natural gas and crude oil as a result of the malfunction of equipment or facilities;
- outages at our facilities;
- ruptures, fires, leaks and explosions; and
- other hazards that could also result in personal injury and loss of life, pollution and other environmental risks, and suspension of operations.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage. The location of our assets, including certain segments of our pipeline systems in or near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas could increase the level of damages resulting from these risks. Despite the precautions we take, events could cause considerable harm to people or property, could result in loss of service available to customers, and could have a material adverse effect on our financial condition and results of operations and ability to make quarterly cash dividends to Class A shareholders.

For example, the Pony Express Pipeline had a temporary embargo of deliveries beginning May 23, 2019 that continued until May 31, 2019 due to extensive flooding on the Cimarron River in Payne County, Oklahoma. The flooding did not damage the Pony Express Pipeline, but our operating costs were temporarily increased after the embargo ended to facilitate the completion of the backlog of deliveries. Further, any walk-up shipper barrels that were not already tendered to Pony Express Pipeline were diverted to other pipelines during the embargo. If any future flooding occurs that results in a longer delivery embargo being necessary, the impact of such embargo could significantly decrease our revenues on the Pony Express Pipeline.

In addition, 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. However, 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. Permanent repairs were completed in September 2018 and the total cost of remediation was approximately \$6.1 million prior to any insurance recoveries. As an additional example, approximately 10,000 bbls of crude oil were released at the Sterling Terminal in January 2017 as a result of a defective roof drain system on a storage tank. While the release was restricted to the containment area designed for such purpose and approximately 9,000 bbls were ultimately recovered, the total cost to remediate the release was approximately \$600,000.

Moreover, maintenance, repair and remediation activities could result in service interruptions on segments of our systems or alter the operational profile of our systems. Any such service interruption or alteration could limit our ability to satisfy customer requirements, could obligate us to provide reservation charge credits to customers for constrained capacity, or could allow existing customers to be solicited by other companies for potential new projects that would compete directly with our services.

We could be required by regulatory authorities to test or undertake modifications to our systems, operations or both that could result in a material adverse impact on our business, financial condition and results of operations. Such actions, including those required by PHMSA, could materially and adversely impact our ability to meet contractual obligations and retain customers, with a resulting material adverse impact on our business and results of operations, and could also limit or prevent our ability to make quarterly cash dividends to our Class A shareholders. Some or all of our costs arising from these operational risks may not be recoverable under insurance, contractual indemnification or increases in rates charged to our customers.

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

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

Our information technology infrastructure is critical to the efficient operation of our business and essential to our ability to perform day-to-day operations. Breaches in our information technology infrastructure or physical facilities, or other disruptions, could result in damage to our assets, service interruptions, safety incidents, damage to the environment, potential liability or the loss of contracts, and have a material adverse effect on our operations, financial position, results of operations and prospects. Further, as cyber incidents continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective and detective measures or to investigate and remediate any vulnerability to cyber incidents.

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

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

Increasing regulatory focus on privacy and security issues and expanding laws could impact our business models, expose us to increased liability, subject us to lawsuits, investigations and other liabilities and restrictions on our operations that could significantly and adversely affect our business.

Along with our own data and information in the normal course of our business, we collect and retain significant volumes of certain types of data, some of which are subject to specific laws and regulations. Complying with varying jurisdictional requirements is becoming increasingly complex and could increase the costs and difficulty of compliance, and violations of

applicable data protection laws, including the European Union General Data Protection Regulation ("GDPR") and the California Consumer Privacy Act ("CCPA"), could result in significant penalties.

The GDPR applies to activities regarding personal data that may be conducted by us, directly or indirectly through vendors and subcontractors, from an establishment in the European Union. As interpretation and enforcement of the GDPR evolves, it creates a range of new compliance obligations, which could cause us to incur costs or require us to change our business practices in a manner adverse to our business. Failure to comply could result in significant penalties of up to a maximum of 4% of our global turnover that may materially adversely affect our business, reputation, results of operations, and cash flows.

The CCPA, which came into effect on January 1, 2020, gives California residents specific rights in relation to their personal information, requires that companies take certain actions, including notifications for security incidents and may apply to activities regarding personal information that is collected by us, directly or indirectly, from California residents. As interpretation and enforcement of the CCPA evolves, it creates a range of new compliance obligations, which could cause us to change our business practices, with the possibility for significant financial penalties for noncompliance that may materially adversely affect our business, reputation, results of operations, and cash flows.

Non-compliance with these and other data protection laws could expose us to regulatory investigations, which could result in fines and penalties. In addition to imposing fines, regulators may also issue orders to stop processing personal data, which could disrupt operations. We could also be subject to litigation from individuals or entities allegedly affected by data protection violations. Any violation of these laws or harm to our reputation could have a material adverse effect on our business, financial condition, results of operations and prospects.

Our insurance coverage may not be adequate.

We are not insured or fully insured against all risks that could affect our business, including losses from environmental accidents or cyber security threats. For example, we do not maintain business interruption insurance in the type and amount to cover all possible losses. In addition, we do not carry insurance for certain environmental exposures, including but not limited to potential environmental fines and penalties, certain business interruptions, named windstorm or hurricane exposures and, in limited circumstances, certain political risk exposures. Further, in the event there is a total or partial loss of one or more of our insured assets, any insurance proceeds that we may receive in respect thereof may be insufficient to effect a restoration of such asset to the condition that existed prior to such loss. In addition, we are either not insured or not fully insured with respect to the legal proceedings described in Note 20 – *Legal and Environmental Matters* and may, depending upon the circumstances, need to pay self-insured retention amounts prior to having losses covered by the insurance providers. The occurrence of any operating risks not fully covered by insurance could have a material adverse effect on our business, financial condition, results of operations and cash flows.

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

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

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

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

- reauthorizing funding for federal pipeline safety programs, increasing penalties for safety violations and establishing additional safety requirements for newly constructed pipelines;
- requiring PHMSA to adopt appropriate regulations within two years and requiring the use of automatic or remote-controlled shutoff valves on new or rebuilt pipeline facilities;
- requiring operators of pipelines to verify MAOP and report exceedances within five days; and

- requiring studies of certain safety issues that could result in the adoption of new regulatory requirements for new and existing pipelines, including changes to integrity management requirements for HCAs, and expansion of those requirements to areas outside of HCAs.

In August 2012, PHMSA published rules to update pipeline safety regulations to reflect provisions included in the Pipeline Safety Act of 2011, including increasing maximum civil penalties from \$0.1 million to \$0.2 million per violation per day of violation and from \$1.0 million to \$2.0 million as a maximum amount for a related series of violations as well as changing PHMSA's enforcement process. In July 2019, PHMSA issued a final rule that increased the per-day violation penalty from \$213,268 to \$218,647 and the maximum penalty for a related series of violations from \$2,132,679 to \$2,186,465, effective July 31, 2019. On October 1, 2019, PHMSA finalized new hazardous liquid pipeline safety regulations extending certain regulatory reporting requirements to hazardous liquid gathering (including oil) pipelines, except transportation-related flow lines, which will be exempt from reporting requirements until further study and cost analyses can be conducted. The final rule requires additional event-driven (e.g., following extreme weather events) and periodic inspections, requires the use of leak detection systems on all new, covered, hazardous liquid pipelines, imposes modified repair criteria, and requires certain pipelines to eventually accommodate in-line inspection tools. The rule becomes effective July 1, 2020.

In addition, on April 8, 2016, PHMSA published a notice of proposed rule-making, or NPRM, addressing natural gas transmission and gathering lines. The proposed rule would include changes to existing integrity management requirements and would expand assessment and repair requirements to pipelines in MCAs, along with other changes. Further, this NPRM would build on the requirements in an Advisory Bulletin PHMSA issued in May 2012, which advised pipeline operators of anticipated changes in annual reporting requirements and that if they are relying on design, construction, inspection, testing, or other data to determine the pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. On October 1, 2019, PHMSA issued a final rule, effective July 1, 2020, that puts in place the first third of the regulations contemplated by the 2016 NPRM; two other phases of rulemaking are expected to address the remainder of items proposed in the 2016 NPRM. The October 2019 final rule requires the completion of periodic integrity reassessments, ordinarily required once every seven years, within six months of written notice from PHMSA; requires operators to consider and account for seismicity in identifying potential threats; requires the reporting of MAOP exceedances of gas transition pipelines; and imposes the proposed record-keeping requirements to confirm MAOP. In addition, the final rule requires operators to perform integrity assessments in MCAs and Class 3 and 4 areas (involving either high density or high consequence structures) at least once by October 1, 2033, and at least once every 10 years thereafter. The final rule also sets specific standards for pressure-relief safety devices on in-line pipeline inspection tools. We are still evaluating the effects of these recently finalized requirements on our operations.

The PIPES Act, enacted on June 22, 2016, reauthorized PHMSA's oil and gas pipeline programs through 2019 and provided for the following new mandates, among others:

- empowers PHMSA to issue emergency orders to individual operators, groups of operators, or the industry upon a written finding that an unsafe condition or practice constitutes or is causing an imminent hazard;
- requires PHMSA, in consultation with other federal agencies, to issue minimum safety standards for underground natural gas storage facilities within two years;
- requires PHMSA to conduct post-inspection briefings outlining any concerns within 30 days and providing written preliminary findings within 90 days to the extent practicable;
- requires liquid pipeline operators to provide safety data sheets on spilled product to the designated federal on-scene coordinator and appropriate state and local emergency responders within 6 hours of telephonic or electronic notice of an accident to the National Response Center; and
- requires PHMSA to publish updates on its website every 90 days on the status of an outstanding final rule required by a statutory mandate.

The reauthorization of these programs for periods subsequent to 2019 remains pending before the U.S. Congress.

On December 14, 2016, PHMSA issued an IFR that addresses safety issues related to downhole facilities, including well integrity, well bore tubing and casing at underground natural gas storage facilities. The IFR incorporates by reference two of the American Petroleum Institute's Recommended Practice standards and mandates certain reporting requirements for operators of underground natural gas storage facilities. Operators of natural gas storage facilities were given one year from January 18, 2017, the effective date of the IFR, to implement this first set of PHMSA regulations governing underground storage fields. PHMSA determined, however, that it will not issue enforcement citations to any operators for violations of provisions of the IFR that had previously been non-mandatory provisions of American Petroleum Institute Recommended Practices 1170 and 1171 until one year after PHMSA issues a final rule.

In July 2018, PHMSA issued an advance notice of proposed rulemaking seeking comment on the class location requirements for natural gas transmission pipelines, and particularly the actions operators must take when class locations change due to population growth or building construction near the pipeline. The associated NPRM is expected in April 2020.

The ultimate costs of compliance with the integrity management rules are difficult to predict. Changes such as advances of in-line inspection tools, identification of additional threats to a pipeline's integrity and changes to the amount of pipe determined to be located in HCAs or expansion of integrity management requirements to areas outside of HCAs, such as the MCAs and Class 3 and 4 areas included in the recently finalized PHMSA rule, can have a significant impact on the costs to perform integrity testing and repairs.

For example, 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 continued performing remediation to increase and maximize its operating capacity over the long-term and spent approximately \$21 million during 2018 for this pipe replacement and remediation work. As of October 2018, the pipeline was returned to its maximum allowable operating capacity.

Additionally, 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 portions of the pipeline converted from natural gas to crude oil service. Remediation work was substantially complete as of March 31, 2018.

There can be no assurance as to the amount or timing of future expenditures required to remediate or resolve these issues, and actual future expenditures may be different from the amounts we currently anticipate. These integrity issues could have a material adverse effect on our business, financial position, results of operations and prospects.

We will continue pipeline integrity testing programs to assess and maintain the integrity of our existing and future pipelines as required by the U.S. Department of Transportation regulations. The results of these tests could cause us to incur potentially material unanticipated capital and operating expenditures for repairs or upgrades.

Further, additional laws, regulations and policies that may be enacted or adopted in the future or a new interpretation of existing laws and regulations could significantly increase the amount of these expenditures. For example, PHMSA issued an Advisory Bulletin in May 2012 which advised pipeline operators that they must have records to document the MAOP for each section of their pipeline and that the records must be traceable, verifiable and complete. Certain of these requirements are included in the recently finalized PHMSA rule that becomes effective July 1, 2020. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing (including hydrotesting) or modifying or replacing facilities to meet the demands of verifiable pressures, could significantly increase costs. TIGT continues to investigate and, when necessary, report to PHMSA the miles of pipeline for which it has incomplete records for MAOP. Additionally, failure to locate such records or verify maximum pressures could require us to operate at reduced pressures, which would reduce available capacity on our natural gas pipeline systems. These specific requirements do not currently apply to crude oil pipelines, but proposed regulations implementing the Pipeline Safety Act of 2011 and future regulations implementing the PIPES Act likely will expand the scope of regulation applicable to crude oil pipelines. There can be no assurance as to the amount or timing of future expenditures required to comply with pipeline integrity regulation, and actual future expenditures may be different from the amounts we currently anticipate. In addition, we may be subject to enforcement actions and penalties for failure to comply with pipeline regulations. Revised or additional regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, financial position, results of operations and prospects. In addition, we may be subject to enforcement actions and penalties for failure to comply with pipeline regulations.

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

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

- CAA and analogous state and local laws, which impose obligations related to air emissions and which the EPA has relied upon as authority for adopting climate change regulatory initiatives;

- CWA and analogous state and local laws, which regulate discharge of pollutants or fill material from our facilities to state and federal waters, including wetlands and which require compliance with state water quality standards;
- CERCLA and analogous state and local laws, which regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for disposal;
- RCRA and analogous state and local laws, which impose requirements for the handling and discharge of hazardous and nonhazardous solid waste from our facilities;
- The SDWA, which ensures the quality of the nation's public drinking water through adoption of drinking water standards and controls the waste fluids from disposal wells into below-ground formations;
- OSHA and analogous state and local laws, which establish workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances, and appropriate control measures;
- NEPA and analogous state and local laws, which require federal agencies to evaluate major agency actions having the potential to significantly impact the environment and which may require the preparation of Environmental Assessments and more detailed Environmental Impact Statements that may be made available for public review and comment;
- The Migratory Bird Treaty Act, or MBTA, and analogous state and local laws, which implement various treaties and conventions between the United States and certain other nations for the protection of migratory birds and, pursuant to which the taking, killing or possessing of migratory birds is unlawful without a permit, thereby potentially requiring the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas;
- ESA and analogous state and local laws, which seek to ensure that activities do not jeopardize endangered or threatened animals, fish and plant species, nor destroy or modify the critical habitat of such species;
- Bald and Golden Eagle Protection Act, or BGEPA, and analogous state and local laws, which prohibit anyone, without a permit issued by the Secretary of the Interior, from "taking" bald or golden eagles, including their parts, nests, or eggs, and defines "take" as "pursue, shoot, shoot at, poison, wound, kill, capture, trap, collect, molest or disturb;"
- OPA and analogous state and local laws, which impose liability for discharges of oil into waters of the United States and requires facilities which could be reasonably expected to discharge oil into waters of the United States to maintain and implement appropriate spill contingency plans; and
- National Historic Preservation Act, or NHPA, and analogous state and local laws, which are intended to preserve and protect historical and archeological sites.

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

There is inherent risk of the incurrence of environmental costs and liabilities in our business, some of which may be material, due to our handling of the products we transport, process, treat, dispose, gather or store, air emissions related to our operations, historical industry operations, and waste disposal practices, such as the prior use of flow meters and manometers containing mercury. These activities are subject to stringent and complex federal, state and local laws and regulations governing environmental protection, including the discharge of materials into the environment and the protection of plants, wildlife, and natural and cultural resources. These laws and regulations can restrict or impact our business activities in many ways, such as restricting the way we handle or dispose of wastes or requiring remedial action to mitigate pollution conditions that may be caused by our operations or that are attributable to former operators. Joint and several, strict liability may be incurred without regard to fault under certain environmental laws and regulations, including but not limited to CERCLA, RCRA and analogous state laws, for the remediation of contaminated areas and in connection with spills or releases of materials associated with oil, natural gas and wastes on, under, or from our properties and facilities, many of which have been used for midstream activities for a number of years, oftentimes by third parties not under our control. We are generally responsible for all liabilities associated with the environmental condition of our facilities and assets, whether acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with certain acquisitions and divestitures, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses,

which may not be covered by insurance. In addition, the steps we could be required to take to bring certain facilities into compliance could be prohibitively expensive, and we might be required to shut down, divest or alter the operation of those facilities, which might cause us to incur losses. We are currently conducting remediation at several sites to address contamination. For these ongoing environmental remediation projects, we spent approximately \$362,000 in 2018, approximately \$518,000 in 2019 and we have budgeted approximately \$1.15 million for 2020.

Private parties, including but not limited to the owners of properties through which our pipelines pass and facilities where our wastes are taken for reclamation or disposal, may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws, regulations and permits issued thereunder, or for personal injury or property damage arising from our operations. Some sites at which we operate are located near current or former third-party hydrocarbon storage, processing, operations or other facilities, and there is a risk that contamination has migrated from those sites to ours that could result in remedial action. In addition, increasingly strict laws, regulations and enforcement policies could materially increase our compliance costs and the cost of any remediation that may become necessary. Our insurance does not cover all environmental risks and costs and may not provide sufficient coverage if an environmental claim is made against us.

For the 2020-2023 time period, as part of its National Compliance Initiatives (previously National Enforcement Initiatives), the EPA is proposing to focus on significant sources of VOCs that have a substantial impact on air quality, without regard to sector, and that may adversely affect vulnerable populations or an area's CAA attainment status. We cannot predict what the results of the current initiative or any future initiative will be, or whether federal, state or local laws or regulations will be enacted in this area. If new regulations are imposed related to oil and gas extraction, the volumes of products, including hydrocarbons and water, that we transport, store, gather, dispose and/or process could decline and our results of operations could be materially and adversely affected.

Our business may be materially and adversely affected by changed regulations and increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits or plans developed thereunder. Also, we might not be able to obtain or maintain from time to time all required environmental regulatory approvals for our operations, or may have to implement contingencies or conditions in order to obtain such approvals. If there is a delay in obtaining any required environmental regulatory approvals, or if we fail to obtain and comply with them, the operation, maintenance or construction of our facilities could be prevented or become subject to additional costs, resulting in potentially material adverse consequences to our business, financial condition, results of operations and cash flows. For instance, in November 2014, the Wyoming Department of Environmental Quality issued a Notice of Violation for violations of Part 60 Subpart OOOO related to the Casper Gas Plant Depropanizer project. The project triggered a modification of the CAA's NSPS 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. In March 2019, TMID and TIGT entered into a Consent Decree to settle this matter with the WDEQ and made an approximately \$0.1 million penalty payment to the WDEQ.

We are also generally responsible for all liabilities associated with the environmental condition of our facilities and assets, whether acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with certain acquisitions and divestitures, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses, which may not be covered by insurance. In addition, the steps we could be required to take to bring certain facilities into compliance could be prohibitively expensive, and we might be required to shut down, divest or alter the operation of those facilities, which might cause us to incur losses. As an example, in August 2011, the EPA and the Wyoming Department of Environmental Quality conducted an inspection of the Leak Detection and Repair Program, or LDAR, at the Casper Plant in Wyoming, and TMID subsequently received a letter from the EPA in September 2011 alleging violations of the Standards of Performance of Equipment Leaks for Onshore Natural Gas Processing Plant requirements under the CAA. After settlement negotiations that extended over several years, TMID and TIGT entered into a Consent Agreement and Final Order to settle this matter with the EPA in February 2019 and made an approximately \$0.1 million penalty payment to the EPA.

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

Also, on January 23, 2020, the EPA and the U.S. Army Corps of Engineers, or Corps, issued a pre-publication version of a final rule to clarify the term "waters of the United States" as it pertains to federal jurisdiction under the CWA. This rule is in direct response to a prior rule, issue June 29, 2015, that many interested parties believed expanded federal jurisdiction under the CWA and that was extensively litigated. It is anticipated that the 2020 final rule defining "waters of the United States" will also be subject to court challenge. The regulation and future interpretation of the term "waters of the United States" rule may require additional Corps or EPA authorizations or involvement in our future operations.

Certain interest groups generally opposed to the development of oil, natural gas and NGLs, and hydraulic fracturing in particular, have from time to time advanced various options for ballot initiatives aimed at significantly limiting or preventing the development of oil, natural gas and NGLs. As discussed above in *"The lack of diversification of our assets and geographic locations could adversely affect our ability to make quarterly cash dividends to our Class A shareholders."*, following the failure of several ballot initiatives to restrict oil and gas development, Colorado passed a new law in April 2019 (Senate Bill 19-181) that, among other things, changes the mission of the COGCC from fostering oil and gas development to instead focus on environmental protection, directs the COGCC and various state agencies to consider new rules imposing stricter environmental controls on the oil and gas industry, and provides local governments with the authority to promulgate their own regulations on oil and gas development. Pursuant to this statutory change, in November 2019, the COGCC issued draft proposed rules related to the oversight of flowlines. The COGCC is also currently soliciting public comment on anticipated future rule changes related to the COGCC's mission, cumulative impacts, and alternative location analyses. While the ultimate impact of the new Colorado law and related rules is currently unknown, this law or passage or enactment of other similar legislation could have a material adverse effect on our customers in the state of Colorado, which could reduce demand for our pipeline services. In addition, our operations could be directly impacted by new rulemakings targeting air emissions from our facilities. For example, the Colorado Department of Public Health and the Environment is considering proposing additional oil and gas measures to reduce VOC and methane emissions from the sector in accordance with the directives of Senate Bill 19-181.

The general trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. There can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be materially different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and prospects.

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

The United States Congress has from time to time considered adopting legislation to reduce emissions of GHGs, and there has been a wide-ranging policy debate, both nationally and internationally, regarding the impact of these gases and possible means for their regulation. In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. In 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. On April 22, 2016, 175 countries, including the United States, signed the Paris Agreement. The Paris Agreement will require countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. However, in November 2019, the United States formally initiated its year-long withdrawal from the Paris Agreement, which will result in an effective exit as early as November 2020.

Following a finding by the EPA that certain GHGs represent an endangerment to human health, the EPA adopted two sets of rules regulating GHG emissions under the CAA, one that requires a reduction in emissions of GHGs from motor vehicles and another that regulates emissions of GHGs from certain large stationary sources. The EPA also expanded its existing GHG emissions reporting requirements to include upstream petroleum and natural gas systems that emit 25,000 metric tons or more of CO₂ equivalent per year. Some of our facilities are required to report under this rule, and operational and/or regulatory changes could require additional facilities to comply with GHG emissions reporting requirements. Furthermore, the EPA adopted a final rule, effective August 2, 2016, imposing more stringent controls on methane and volatile organic compounds emissions from oil and gas development, production, and transportation operations under the New Source Performance Standard, or NSPS, program. In September 2019, the EPA proposed a rule to reconsider, rescind, and amend various requirements of the NSPS standard, including removing sources in the transmission and storage segment from the regulated source category, rescinding the NSPS (including both VOC and methane requirements) applicable to those sources, and rescinding the methane-specific requirements of the NSPS applicable to sources in the production and processing segments. Alternatively, EPA proposes to rescind the methane requirements of the NSPS applicable to all oil and natural gas sources, without removing any sources from the source category. However, the NSPS rule currently remains in effect. In 2016, the EPA also finalized a rule regarding the alternative criteria for aggregating multiple small surface sites into a single source for air quality permitting purposes. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby

triggering more stringent air permitting processes and requirements across the oil and gas industry. The BLM also adopted new rules, effective January 17, 2017, to reduce venting, flaring, and leaks during oil and natural gas production activities on onshore federal and Indian leases. This rule was suspended, stayed, and reinstated before the BLM issued a final rule in September 2018 that rescinds and revises many of the requirements of the 2017 rule. The revision rule is being challenged in the U.S. District Court for the Northern District of California but currently remains in effect. In addition, many states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, to acquire and surrender emission allowances with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved.

The adoption of legislation or regulations imposing reporting or permitting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur additional costs to reduce emissions of GHGs associated with our operations, could adversely affect our operations in the absence of any permits that may be required to regulate emission of GHGs, or could adversely affect demand for the crude oil and natural gas we transport, gather, process, or otherwise handle. For instance, the EPA's recently finalized NSPS rules or future rules under CAA Section 111(d) could result in the direct regulation of GHGs associated with our operations, including the operations of Rockies Express. We are not able at this time to estimate such increased costs; however, they could be significant. While we may be able to recover some or all of such increased costs in the rates charged by our processing facilities, such recovery of costs is uncertain and may depend on the terms of our contracts with our customers.

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

A sizeable portion of our customers' production comes from hydraulically fractured wells. Hydraulic fracturing is a common practice that is used to stimulate production of hydrocarbons from tight formations. The process typically involves the injection of water, sand and a small percentage of chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is regulated by state agencies, typically the state's oil and gas commission; however, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the SDWA and has released draft permitting guidance for hydraulic fracturing activities that use diesel in fracturing fluids in those states where the EPA is the permitting authority. A number of federal agencies, including the EPA and the U.S. Department of Energy, are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. For example, on May 19, 2014, the EPA published an advance notice of rulemaking under the Toxic Substances Control Act, to gather information regarding the potential regulation of chemical substances and mixtures used in oil and gas exploration and production. In May 2016, the EPA issued final rules that update new source performance standard requirements and that will impose more stringent controls on methane and volatile organic compounds emissions from oil and gas development and production operations, including hydraulic fracturing and other well completion activity. In September 2019, the EPA proposed a rule to reconsider, rescind, and amend various requirements of the NSPS standard. However, the rule currently remains in effect. The EPA also issued a final rule in June 2016 that prohibits the discharge of hydraulic fracturing wastewater from onshore unconventional oil and gas extraction facilities into publicly owned sewage treatment plants. Also, the BLM adopted new rules effective January 17, 2017, to reduce venting, flaring, and leaks during oil and natural gas production activities on onshore federal and Indian leases. This rule was suspended, stayed, and reinstated before the BLM issued a final rule in September 2018 that rescinds and revises many of the requirements of the 2017 rule. The revision rule is being challenged in the U.S. District Court for the Northern District of California but currently remains in effect.

Congress from time to time has considered the adoption of legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition, some states, including those in which we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular, and in some cases, may seek to ban hydraulic fracturing entirely. Some state and local authorities have considered or imposed new laws and rules related to hydraulic fracturing, including temporary or permanent bans, additional permit requirements, operational restrictions and chemical disclosure obligations on hydraulic fracturing in certain jurisdictions or in environmentally sensitive areas. Other governmental agencies, including the U.S. Department of Energy and the EPA, have evaluated or are evaluating various other aspects of hydraulic fracturing such as the potential environmental effects of hydraulic fracturing on drinking water and groundwater. On December 13, 2016, the EPA released a study of the potential adverse effects that hydraulic fracturing may have on water quality and public health, concluding that there is scientific evidence that hydraulic fracturing activities potentially can impact drinking water resources in the United States under some circumstances.

If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or significantly more costly for our customers to perform fracturing to stimulate production from tight formations. Restrictions on hydraulic fracturing could also reduce the volume of crude oil, natural gas or other hydrocarbons that our customers produce, and could thereby adversely affect our revenues and results of operations. Compliance with such rules could also generally result in additional costs, including increased capital expenditures and operating costs, for us and our customers, which could ultimately decrease end-user demand for our services and could have a material adverse effect on our business.

Our produced water disposal operations may be subject to additional regulation and liability or claims of environmental damages.

We operate produced water disposal wells which are regulated under the federal SDWA as Class II wells and under state and local laws. State and local laws and regulations that govern these operations can be more stringent than the SDWA. In addition, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may also incur material environmental costs and liabilities. Furthermore, our insurance may not provide sufficient coverage in the event an environmental claim is made against us. In addition, although the disposal wells have received certain governmental regulatory licenses, permits or approvals, this does not shield us from potential claims from third parties claiming contamination of their water supply or other environmental damages. Remediation of environmental contamination or damages can be extremely costly and such costs, if we are found liable, may have a material adverse effect on our business, financial condition and results of operations.

Produced water injection well operations and hydraulic fracturing may cause induced seismicity.

State and federal regulatory agencies recently have focused on a possible connection between hydraulic fracturing related activities and the increased occurrence of seismic activity. When caused by human activity, such events are called induced seismicity. In a few instances, operators of produced water injection wells in the vicinity of seismic events have been ordered to reduce produced water injection volumes or suspend operations. Some state regulatory agencies, including those in Colorado and Texas, have modified their regulations to account for induced seismicity. Regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. In 2015, the United States Geological Study, or USGS, identified eight states, including Colorado, Oklahoma and Texas, with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. The USGS also produced a one-year 2017 induced seismicity model that forecast an elevated hazard from induced seismicity in Oklahoma compared to the hazard calculated for seismicity before 2009. In addition, a number of lawsuits have been filed, most recently in Oklahoma, alleging that produced water disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. The Oklahoma Corporation Commission, or OCC, has adopted a plan calling for mandatory reductions in oil and gas wastewater disposal well volumes, the implementation of which has involved reductions of injection or shut-ins of disposal wells. The OCC has also released guidance to operators in the SCOOP and STACK areas for management of certain seismic activity that may be related to hydraulic fracturing activities. These developments could result in additional regulation and restrictions on the use of produced water injection wells and hydraulic fracturing. Such regulations and restrictions could have a material adverse effect on our business, financial condition and results of operations.

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

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

We have certain long-term fixed priced natural gas and crude oil transportation contracts that cannot be adjusted even if our costs increase. As a result, our costs could exceed our revenues.

As of December 31, 2019, approximately 59% of our contracted natural gas transportation firm capacity was provided under long-term, fixed price "negotiated or discount rate" contracts that are not subject to adjustment, even if our cost to perform such services exceeds the revenues received from such contracts, and, as a result, our costs could exceed our revenues received under such contracts. It is possible that costs to perform services under our "negotiated or discount rate" contracts will exceed the negotiated or discounted rates. It is also possible with respect to discounted rates that if our filed "recourse rates" should ever be reduced below applicable discounted rates, we would only be allowed by the FERC to charge the lower recourse rates, since FERC policy does not allow discount rates to be charged to the extent that they exceed applicable recourse rates. If these events were to occur, it could decrease the cash flow realized by our assets and, therefore, the cash we have available for dividends to our Class A shareholders.

Under FERC policy, a regulated service provider and a customer may mutually agree to sign a contract for service at a "negotiated rate," which is generally fixed between the natural gas pipeline and the shipper for the contract term and does not necessarily vary with changes in the level of cost-based "recourse rates," provided that the affected customer is willing to agree to such rates and that the FERC has accepted the negotiated rate agreement. These "negotiated or discount rate" contracts are not generally subject to adjustment for increased costs which could be caused by inflation or other factors relating to the specific facilities being used to perform the services. Any shortfall of revenue, representing the difference between "recourse rates" (if higher) and negotiated or discounted rates, under current FERC policy, may be recoverable from other shippers in certain circumstances. For example, the FERC may recognize this shortfall in the determination of prospective rates in a future rate case. However, if the FERC were to disallow the recovery of such costs from other customers, it could decrease the cash flow realized by our assets and, therefore, the cash we have available for dividends to our Class A shareholders.

Rates under Pony Express' TDAs are typically subject to change only per contract terms and conditions, including Pony Express' right to file changes to contract rates to reflect annual index percentage adjustments published by the FERC. We generally cannot file for rate increases with respect to committed shippers who have signed TDAs, other than to reflect annual index adjustments or to recover compliance costs imposed by governmental actions.

A significant amount of the revenue currently generated by our Gathering, Processing & Terminalling segment depends on whether our customers actually use our services. A period of low usage will reduce our revenue in our Gathering, Processing & Terminalling segment and could result in an impairment of the goodwill at the Midstream Facilities reporting unit within this segment.

Many of our water business services and natural gas gathering and processing customers are not subject to "take or pay" obligations. Rather, a significant amount of the revenue currently generated by our Gathering, Processing & Terminalling segment depends on whether our customers actually use our services. If these customers do not utilize our services, revenue for our Gathering, Processing & Terminalling segment will decline.

For example, the decreased commodity prices since 2015 contributed to a significant drop in actual volumes from several producers from which TMID receives natural gas for processing. If processing volumes at TMID do not continue recovering over time, our revenue will decline in the Gathering, Process & Terminalling segment and we could have an impairment of the goodwill at the Midstream Facilities reporting unit within this segment.

We are exposed to direct commodity price risk in our Gathering, Processing & Terminalling segment, including certain of TMID's contracts and the utilization of commodity derivatives by Stanchion, and our exposure to direct commodity price risk may increase in the future.

TMID operates under three types of contracts, two of which directly expose our cash flows in the Gathering, Processing & Terminalling segment to increases and decreases in the price of natural gas and NGLs: percent of proceeds and keep whole processing contracts. We do not currently hedge the commodity exposure inherent in these types of processing contracts, and as a result, our revenues and results of operations are impacted by fluctuations in the prices of natural gas and NGLs.

Percent of proceeds processing contracts generally provide upside in high commodity price environments, but result in lower margins in low commodity price environments. Under keep whole processing contracts, our revenues and our cash flows generally increase or decrease as the prices of natural gas and NGLs fluctuate. The relationship between natural gas prices and NGL prices may also affect our profitability. When natural gas prices are low relative to NGL prices, it is more profitable for us to process natural gas under keep whole arrangements. When natural gas prices are high relative to NGL prices, it is less profitable for us and our customers to process natural gas both because of the higher value of natural gas and the increased cost (principally that of natural gas as a feedstock and a fuel) of separating the mixed NGLs from the natural gas. As a result, we may experience periods in which higher natural gas prices relative to NGL prices reduce our processing margins or reduce the volume of natural gas processed at some of our plants. In addition, NGL prices have historically been related to the market price of oil and as a result any significant changes in oil prices could also indirectly impact our operations. Indirectly, reduced commodity prices impact us through reduced exploration and production activity, which results in fewer opportunities for new business to offset natural volume declines. NGL and natural gas prices are volatile and are impacted by changes in the supply and demand for NGLs and natural gas, as well as market uncertainty. For example, from the second half of 2014 through the first half of 2016, natural gas and crude oil prices declined substantially. Throughout 2019, the industry again experienced sustained lower natural gas prices. These declines directly and indirectly resulted in lower processing volumes and realizations on our percent of proceeds and keep whole processing contracts.

In 2017, we also began utilizing commodity derivatives in connection with the operations of our crude oil marketing subsidiary, Stanchion. Our portfolio of derivative and other energy contracts may consist of contracts to buy and sell commodities that are settled by the delivery of the commodity or cash. If the values of these contracts change in a direction or manner that we do not anticipate or cannot manage, it could negatively affect our results of operations. If a performance failure were to occur in one of our contracts, we might incur losses in addition to amounts, if any, already recognized in our financial

statements or paid to, or received from, counterparties. As a result, our business, results of operations, financial condition and ability to pay quarterly cash dividends to our Class A shareholders may be adversely affected.

The TEP revolving credit facility and the indentures governing the TEP senior notes contain certain restrictions which could adversely affect our business, financial condition, results of operations and ability to make quarterly cash dividends to our Class A shareholders.

We are dependent upon certain earnings and cash flow generated by our operations in order to meet our debt service obligations. The TEP revolving credit facility, the indenture governing its 4.75% senior notes due 2023 (the "2023 Notes") the indenture governing its 5.50% senior notes due 2024 (the "2024 Notes"), and the indenture governing its 5.50% senior notes due 2028 (the "2028 Notes") contain, and any future financing agreements may contain, operating and financial restrictions and covenants that could restrict our ability to finance future operations or capital needs, or to expand or pursue our business activities, which may, in turn, limit our ability to make quarterly cash dividends. For example, the TEP revolving credit facility limits TEP's ability and the ability of its restricted subsidiaries to, among other things:

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

The TEP revolving credit facility also contains covenants requiring TEP to maintain certain financial ratios. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot assure you that TEP will meet those ratios and tests. Further, TEP's obligations under the revolving credit facility are (i) guaranteed by TEP and each of its existing and subsequently acquired or organized direct or indirect wholly-owned domestic subsidiaries, subject to its ability to designate certain subsidiaries as "Unrestricted Subsidiaries," and (ii) secured by a first priority lien on substantially all of the present and after acquired property owned by TEP and each guarantor (other than real property interests related to its pipelines).

Similarly, the indenture governing the 2024 Notes 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, repurchase equity securities or redeem subordinated securities; (iv) make investments; (v) restrict distributions, loans or other asset transfers from our restricted subsidiaries; (vi) consolidate with or merge with or into, or sell substantially all its properties to, another person; (vii) sell or otherwise dispose of assets, including equity interests in subsidiaries; and (viii) enter into transactions with affiliates.

In addition, the indentures governing the 2023 Notes and the 2028 Notes contain 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 of its properties to, another person.

The provisions of the TEP revolving credit facility and the indentures governing its senior notes may affect our ability to obtain future financing and pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of the TEP revolving credit facility or the indentures governing its senior notes, including a failure to meet any of the required financial ratios and tests, could result in a default or an event of default that could enable TEP's lenders or the holders of the senior notes to declare the outstanding principal of that indebtedness, together with accrued and unpaid interest, to be immediately due and payable, and in the case of the TEP revolving credit facility, would prohibit TEP's ability to make distributions. If the payment of the indebtedness under the TEP revolving credit facility is accelerated and we are unable to repay the indebtedness in full, the lenders could foreclose on the assets pledged by TEP and the guarantors under the TEP revolving credit facility. In that case, these assets may be insufficient to repay such indebtedness in full, and our Class A shareholders could experience a partial or total loss of their investment.

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

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

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- our funds available for operations, future business opportunities and dividends to Class A shareholders will be reduced by that portion of our cash flow required to make interest payments on our indebtedness;

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

Our ability to service our indebtedness depends upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing dividends, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. Taking any of these actions is likely to reduce the value of an investment in us. Plus, we may not be able to effect any of these actions on satisfactory terms or at all.

Increases in interest rates could adversely impact our Class A share price, our ability to issue equity or incur indebtedness for acquisitions or other purposes and our ability to make quarterly cash dividends at our intended levels.

The interest rate on borrowings under the TEP revolving credit facility float based upon one or more of the prime rate, the U.S. federal funds rate or LIBOR. As a result, those borrowings, as well as borrowings under possible future credit facilities or debt offerings, could be higher than current levels, causing our financing costs to increase accordingly. We do not currently hedge the interest rate risk on borrowings under the TEP revolving credit facility.

As with other yield-oriented securities, our Class A share price may be impacted by the level of our cash dividend and implied dividend yield. The dividend yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our Class A shares, and a rising interest rate environment could have an adverse impact on our Class A share price, our ability to issue equity or incur indebtedness for acquisitions or other purposes and our ability to maintain or increase quarterly cash dividends on our Class A shares.

Rockies Express has a substantial amount of indebtedness and Rockies Express may not be able to generate a sufficient amount of cash flow to meet its debt service obligations.

As of January 31, 2020, Rockies Express had \$2.8 billion of senior notes outstanding, of which \$750 million will mature on April 15, 2020 and are expected to be redeemed in March 2020, \$400 million will mature in 2025, \$550 million will mature in 2029, \$350 million will mature in 2030, \$250 million will mature in 2038 and \$500 million will mature in 2040. Further, Rockies Express has a revolving credit facility with \$150 million of borrowing capacity that matures in November 2024.

The substantial indebtedness held by Rockies Express could have important consequences. For example, it could:

- make it more difficult for Rockies Express to satisfy its obligations with respect to its indebtedness;
- increase the vulnerability of Rockies Express to general adverse economic and industry conditions;
- limit the ability of Rockies Express to obtain additional financing for future working capital, capital expenditures and other general business purposes;
- require Rockies Express to dedicate a substantial portion of its cash flow from operations to payments on its indebtedness, thereby reducing the availability of cash flow for operations and other purposes;
- limit its flexibility in planning for, or reacting to, changes in its business and the industry in which Rockies Express operates;
- place Rockies Express at a competitive disadvantage compared to its competitors that have less indebtedness; and
- have a material adverse effect if Rockies Express fails to comply with the covenants in the indenture relating to its notes or in the instruments governing its other indebtedness.

Other than the indenture governing the senior notes due in 2025 and 2030, the terms of the indentures governing the existing Rockies Express notes do not restrict the amount of additional unsecured indebtedness Rockies Express may incur, and the agreements governing its revolving credit facility permit additional unsecured borrowings. If new indebtedness is added to the current indebtedness levels, these related risks could increase.

Rockies Express' ability to make scheduled payments or to refinance its obligations with respect to its indebtedness will depend on its financial and operating performance, which, in turn, is subject to prevailing economic conditions and to financial, business, and other factors beyond its control. In addition, a significant amount of Rockies Express' revenue in 2018 and 2019 was generated by long-term west-to-east contracts that have expired in 2019. The re-contracting of the capacity made available from these expirations has been at lower rates than those expiring contracts and we expect the re-contracting of any remaining capacity for west-to-east transport will also be at lower rates. As a result, we expect lower cash flows in periods subsequent to such contract expirations. We cannot assure you that Rockies Express' operating performance, cash flow and capital resources will be sufficient for payment of its indebtedness in the future. In the event that Rockies Express is required to dispose of

material assets or restructure its indebtedness to meet its debt service and other obligations, we cannot assure you as to the terms of any such transaction or how soon any such transaction could be completed.

If Rockies Express' cash flow and capital resources are insufficient to fund its debt service obligations, it may be forced to sell material assets, obtain additional capital, including through capital contributions from its members, or restructure its indebtedness. The payment of additional capital contributions by us to Rockies Express to fund such obligations would reduce the amount of cash available to make dividends to our Class A shareholders.

Rockies Express' revolving credit facility contains certain restrictions which could limit its financial flexibility and increase its financing costs.

Rockies Express' revolving credit facility contains restrictive covenants that may prevent it from engaging in various transactions that Rockies Express deems beneficial and that may be beneficial to Rockies Express. The revolving credit facility generally requires Rockies Express to comply with various affirmative and negative covenants, including a limit on the leverage ratio (as defined in each credit agreement) of Rockies Express and restrictions on:

- incurring secured indebtedness;
- entering into mergers, consolidations and sales of assets;
- granting liens;
- entering into transactions with affiliates; and
- making restricted payments.

Instruments governing any future indebtedness at Rockies Express may contain similar or more restrictive provisions. Rockies Express' ability to respond to changes in business and economic conditions and to obtain additional financing, if needed, may be restricted.

We do not own most of the land on which our assets are located, which could disrupt our operations and subject us to increased costs.

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

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

Our interstate natural gas pipeline systems have federal eminent domain authority in certain instances. To the extent federal eminent domain authority is not available, the availability of eminent domain for future pipeline expansions varies from state to state, depending upon the laws of the particular state and in some states it may not be available at all. Regardless, we must compensate landowners for the use of their property, which may include any loss of value to the remainder of their property not being used by us, which are sometimes referred to as "severance damages." Severance damages are often difficult to quantify and their amount can be significant. In eminent domain actions, such compensation may be determined by a court. Our inability to exercise the power of eminent domain could negatively affect our business if we were to lose the right to use or occupy the property on which our crude oil or natural gas pipeline systems are located. In addition, the cost to voluntarily obtain rights-of-way from landowners has increased in recent years as landowners more frequently seek to collectively negotiate. For example, a number of landowner groups sought to negotiate collectively with respect to the Cheyenne Connector Pipeline project and in some instances, these groups also raised objections at the hearings held to consider the issuance of the land use permit from Weld County, Colorado. The collective efforts by such landowner groups added to the costs associated with acquisition of the right-of-way, delayed the issuance of a local land use permit from Weld County, Colorado and increased the risk that FERC would not issue a certificate of public convenience and necessity for the project.

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

The transportation, storage and terminalling of crude oil, the transportation, storage and processing of natural gas, and the transportation, gathering, recycling and disposal of water requires skilled laborers in multiple disciplines such as equipment operators, mechanics and engineers, among others. If we experience shortages of skilled labor in the future, our labor and overall productivity or costs could be materially and adversely affected. If our labor prices increase or if we experience materially increased health and benefit costs for employees, our results of operations could be materially and adversely affected.

If we fail to develop or maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, shareholders could lose confidence in our financial reporting, which would harm our business and the trading price of our Class A shares.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a publicly traded company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results will be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future, that we will be able to prevent fraud, or that we will be able to comply with our obligations under Section 404 of the Sarbanes Oxley Act of 2002. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our Class A shares.

New technologies, including those involving recycling of produced water or the replacement of water in fracturing fluid, may adversely affect our future results of operations and financial condition.

The produced water disposal industry is subject to the introduction of new waste treatment and disposal techniques and services using new technologies including those involving recycling of produced water, some of which may be subject to patent protection. As competitors and others use or develop new technologies or technologies comparable to our water business services in the future, we may lose market share or be placed at a competitive disadvantage. For example, some companies have successfully used propane as the fracturing fluid instead of water. Further, we may face competitive pressure to implement or acquire certain new technologies at a substantial cost. Some of our competitors may have greater financial, technical and personnel resources than we do, which may allow them to gain technological advantages or implement new technologies before we can. Additionally, we may be unable to implement new technologies or products at all, on a timely basis or at an acceptable cost. New technology could also make it easier for our customers to vertically integrate their operations or reduce the amount of waste produced in oil and natural gas drilling and production activities, thereby reducing or eliminating the need for third-party disposal. Limits on our ability to effectively use or implement new technologies, including in its water business services, may have a material adverse effect on our business, financial condition and results of operations.

Rockies Express is a joint venture and our investment could be adversely affected by our lack of sole decision-making authority.

We do not control Rockies Express through our ownership of a 75% membership interest. Under the limited liability company agreement of Rockies Express, substantially all matters are decided by a vote of 80% of the membership interests, other than certain fundamental decisions that require a vote of 90% of the membership interests. As a result, all the decisions of the Rockies Express members effectively require unanimous approval of us and the other member of Rockies Express, Phillips 66. Thus, our investment in Rockies Express involves risks that are not present when we are able to exercise control over an asset, including the possibility that the unaffiliated third-party member of Rockies Express might become bankrupt, fail to fund its required capital contributions or otherwise attempt to make business decisions with respect to Rockies Express that we do not believe are in its best interest. Moreover, under the Rockies Express limited liability company agreement, we are required to provide certain capital contributions in order to fund expenditures contemplated by Rockies Express' annual budget, and may be required to provide capital contributions under certain circumstances specified in the Rockies Express limited liability company agreement if determined to be reasonably necessary by a vote of Rockies Express' members.

As an unaffiliated third-party member of Rockies Express, Phillips 66 may have economic or other business interests or goals that are inconsistent with our business interests or goals. The Rockies Express limited liability company agreement expressly permits Rockies Express members to make decisions with respect to their ownership interest without taking into account the interests of Rockies Express or any other member of Rockies Express.

Our membership interest in Rockies Express is subject to a right of first refusal, which may make it more difficult to sell our interest in Rockies Express in the future.

Under the terms of Rockies Express' limited liability company agreement, if any member desires to transfer its membership interest to an unaffiliated third party, each other member first has a right to purchase its proportionate share of the membership interest being sold. If we desire to sell all or any portion of our interest in Rockies Express to an unaffiliated third-party in the future, we will be required to first offer the sale of our membership interest to the other member, who will have 30 days to elect to purchase their proportionate interest before any sale or transfer to a third party may be consummated. This requirement could make it difficult for us to sell our interest in Rockies Express.

Risks Inherent in an Investment in Us

Our quarterly cash dividends to our Class A shareholders are not cumulative.

Except as discussed in Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations, "Dividends," our quarterly cash dividends to our Class A shareholders are not cumulative. Consequently, if cash dividends on our Class A shares are not paid with respect to any fiscal quarter then our Class A shareholders will not be entitled to receive that quarter's payments in the future.

Our partnership agreement requires that we distribute our available cash on a quarterly basis, which could limit our ability to grow and make acquisitions.

Our partnership agreement requires us to distribute our available cash to our Class A shareholders on a quarterly basis. Accordingly, we will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow.

In addition, because we intend to dividend our available cash, subject to our agreement pursuant to the Take-Private Merger Agreement not to pay dividends during the pendency of the transactions contemplated by the Take-Private Merger Agreement, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional shares in connection with any acquisitions or expansion capital expenditures, the payment of dividends on those additional shares may increase the risk that we will be unable to maintain or increase our per share dividend level. There are no limitations in our partnership agreement on our ability to issue additional shares, including shares ranking senior to the Class A shares. The incurrence of additional commercial borrowings or other indebtedness to finance our growth strategy would result in increased interest expense, which in turn may impact the cash available for dividends to our Class A shareholders.

If we issue additional Class A shares without canceling an equivalent number of Class B shares, Tallgrass Equity incurs additional debt, we incur debt or we or Tallgrass Equity are required to pay taxes, the payment of distributions on those additional Class A shares or interest on that debt or payment of such taxes could increase the risk that we will be unable to maintain or increase our cash dividend levels.

Restrictions in TEP's and Rockies Express' respective credit facilities and the indentures governing TEP's and Rockies Express' existing senior notes could limit their ability to make distributions, thereby limiting our ability to make quarterly cash dividends to our Class A shareholders. Any credit facility we enter into in the future could pose similar restrictions that would further limit our ability to make quarterly cash dividends.

TEP's and Rockies Express' respective credit facilities and the indentures governing TEP's and Rockies Express' existing senior notes contain various operating and financial restrictions and covenants. TEP's and Rockies Express' respective ability to comply with these restrictions and covenants may be affected by events beyond their control, including prevailing economic, financial and industry conditions. If TEP or Rockies Express are unable to comply with these restrictions and covenants, any indebtedness under these credit facilities and indentures may become immediately due and payable and TEP's and Rockies Express' respective lenders' commitment to make further loans under their revolving credit facilities may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments.

We may enter into a credit facility in the future that would impose similar restrictions to those discussed above. In addition, our payment of principal and interest on any future indebtedness would reduce our cash available for dividends to our Class A shares.

For more information regarding the TEP revolving credit facility and the indentures governing TEP's existing senior notes, please see the section above "—The TEP revolving credit facility and the indentures governing the TEP senior notes contain certain restrictions which could adversely affect our business, financial condition, results of operations and ability to make quarterly cash dividends to our Class A shareholders." For more information regarding Rockies Express' revolving credit facility and the indentures governing Rockies Express' existing senior notes, please see the sections above "—Rockies Express has a substantial amount of indebtedness and Rockies Express may not be able to generate a sufficient amount of cash flow to

meet its debt service obligations." and "—Rockies Express' revolving credit facility contains certain restrictions which could limit its financial flexibility and increase its financing costs."

Our shareholders do not vote in the election of our general partner's directors. The Sponsor Entities own a sufficient number of shares to allow them to prevent the removal of our general partner and to strongly influence all other matters requiring shareholder approval.

Our shareholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Our general partner is responsible for conducting our business and managing our operations. Our shareholders do not have the ability to elect our general partner or the members of the board of directors of our general partner.

The members of the board of directors of our general partner, including the independent directors, are currently designated and elected by BIP through the exercise of the rights of the sole member of our general partner, subject only to certain contractual rights in the Equityholders Agreement entered into between certain affiliates of the Sponsor Entities and BIP's co-investors in March 2019 and limitations in the Take-Private Merger Agreement. As a result of these rights, including the ability to cause or prevent a change in the composition of the board of directors of our general partner or a change in control of TGE, BIP effectively controls our business and affairs.

If our Class A shareholders are dissatisfied with the performance of our general partner, they have little ability to remove our general partner. Our general partner may not be removed except by vote of the holders of at least 80% of our outstanding shares, voting together as a single class. As of December 31, 2019, the Sponsor Entities owned approximately 44.1% of the combined voting power of our Class A and Class B shares. This ownership level enables the Sponsor Entities to prevent our general partner's removal. In addition, with their combined voting power, the Sponsor Entities are able to strongly influence all other matters requiring shareholder approval, regardless of whether or not unaffiliated shareholders believe that the transaction is in their own best interests.

As a result of these provisions, the price at which our shares trade may be lower because of the absence or reduction of a takeover premium in the trading price.

Our general partner may cause us to issue additional Class A shares or other equity securities, including equity securities that are senior to our Class A shares, without your approval, which may adversely affect you.

Our general partner has the ability to cause us to issue an unlimited number of additional Class A shares, or other equity securities of equal rank with the Class A shares, without shareholder approval. In addition, we may issue an unlimited number of shares that are senior to our Class A shares in right of dividend, liquidation and voting. Except for Class A shares issued in connection with the exercise by any Exchange Right Holder of its right to exchange a Class B share for a Class A share (the "Exchange Right"), each of which will result in the cancellation of an equivalent number of Class B shares and therefore have no effect on the total number of outstanding shares, the issuance of additional Class A shares, or other equity securities of equal or senior rank, may have the following effects:

- each shareholder's proportionate ownership interest in us may decrease;
- the amount of cash available for dividends on each Class A share may decrease;
- the relative voting strength of each previously outstanding Class A share may be diminished;
- the date upon which we begin paying material U.S. federal income taxes, or upon which a material portion of our dividends constitute taxable dividend income for U.S. federal income tax purposes, could be accelerated; and
- the market price of the Class A shares may decline.

You may not have limited liability if a court finds that shareholder action constitutes control of our business.

Under Delaware law, you could be held liable for our obligations to the same extent as a general partner if a court determined that the right or the exercise of the right by our shareholders (who hold limited partner interests despite the fact that we use the term "shareholder" in this Annual Report) as a group to remove or replace our general partner, to approve some amendments to the partnership agreement or to take other action under our partnership agreement constituted participation in the "control" of our business. Additionally, the limitations on the liability of holders of limited partner interests for the liabilities of a limited partnership have not been clearly established in many jurisdictions.

Furthermore, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that, under some circumstances, a shareholder may be liable to us for the amount of a dividend for a period of three years from the date of the dividend.

Our partnership agreement restricts the rights of shareholders owning 20% or more of our shares.

Our shareholders' voting rights are restricted by the provision in our partnership agreement generally providing that any shares held by a person or group that owns 20% or more of any class of shares then outstanding, other than our general partner or its affiliates and persons who acquired such shares with the prior approval of our general partner's board of directors, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of our shareholders to call meetings or to acquire information about our operations, as well as other provisions limiting our shareholders' ability to influence the manner or direction of our management. As a result, the price at which our Class A shares trade may be lower because of the absence or reduction of a takeover premium in the trading price.

Future sales of our Class A shares in the public market, including sales of Class A shares by the Exchange Right Holders after the exercise of the Exchange Right, could reduce our Class A share price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

Subject to certain limitations and exceptions, the Exchange Right Holders may cause the exchange of their TE Units (together with a corresponding number of Class B shares) for Class A shares (on a one-for-one basis, subject to customary conversion rate adjustments for equity splits and reclassification and other similar transactions) and then sell those Class A shares in the public market. For example, certain participating Exchange Right Holders exercised their exchange right and sold 10,350,000 Class A shares in a secondary offering completed in November 2016. In addition, for the years ended December 31, 2019 and 2018, 21,751,018 Class A shares and 2,821,332 Class A shares, respectively, were issued and an equal number of Class B shares were canceled, as a result of the exercise of the exchange right. Further, in accordance with an amended and restated registration rights agreement entered into with the Exchange Right Holders, we have registered the resale of 125,291,659 Class A shares, 102,136,875 of which remain issuable upon exercise of the Exchange Right, pursuant to our Form S-3 (File No. 333-225382) filed with the SEC on June 1, 2018, which became effective June 13, 2018.

We may also issue additional Class A shares or convertible securities in subsequent public or private offerings. We cannot predict the size of future issuances of our Class A shares or securities convertible into Class A shares or the effect, if any, that future issuances and sales of our Class A shares, including sales of Class A shares by the Exchange Right Holders after the exercise of the Exchange Right, will have on the market price of our Class A shares. Sales of substantial amounts of our Class A shares (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our Class A shares.

A valuation allowance on our deferred tax asset could reduce our earnings.

A significant deferred tax asset was recorded as a result of certain reorganization transactions completed in connection with the TGE IPO. In November 2016, we completed a Secondary Offering of Class A shares, which resulted in the recognition of an additional deferred tax asset. The aggregate deferred tax asset was \$318.2 million as of December 31, 2019. GAAP requires that a valuation allowance must be established for deferred tax assets when it is more likely than not that they will not be realized. If we were to determine that a valuation allowance was appropriate for our deferred tax asset, we would be required to take an immediate charge to earnings with a corresponding reduction of partners' equity and increase in balance sheet leverage as measured by debt to total capitalization.

The NYSE does not require a limited partnership like us to comply with certain of its corporate governance requirements.

Because we are a limited partnership, the NYSE does not require our general partner to have a majority of independent directors on its board of directors. The NYSE also does not require our general partner to establish a compensation committee or a nominating and corporate governance committee. Accordingly, our shareholders do not have the same protections afforded to certain corporations that are subject to all the NYSE corporate governance requirements. In addition, as a limited partnership, we are not required to seek shareholder approval for issuances of Class A shares including issuances in excess of 20% of outstanding equity securities, or for issuances of equity to certain affiliates.

We may incur liability as a result of our ownership of TEP's general partner.

Under Delaware law, a general partner of a limited partnership is generally liable for the debts and liabilities of the partnership for which it serves as general partner, subject to the terms of any indemnification agreements contained in the partnership agreement and except to the extent the partnership's contracts are non-recourse to the general partner. As a result of our structure, we indirectly own and control the general partner of TEP. To the extent the indemnification provisions in TEP's partnership agreement or non-recourse provisions in our contracts are not sufficient to protect TEP GP from such liability, we may in the future incur liabilities as a result of our indirect ownership of TEP's general partner. Please read the section entitled "*Risks Related to Conflicts of Interest.*"

Risks Related to Conflicts of Interest

Our existing organizational structure and the relationships among us, our general partner, BIP, the Sponsor Entities, and their affiliated entities and owners present the potential for conflicts of interest. Moreover, additional conflicts of interest may arise in the future among us and the entities affiliated with any general partner or similar interests we acquire.

Conflicts of interest may arise as a result of our organizational structure and the relationships among us, our general partner, and its direct and indirect owners, which include BIP, the Sponsor Entities and their affiliated entities and owners.

Our partnership agreement defines the duties of our general partner (and, by extension, its officers and directors). Our general partner's board of directors or its conflicts committee has authority on our behalf to resolve any conflict involving us and they have broad latitude to consider the interests of all parties to the conflict.

Conflicts of interest may arise between us and our shareholders, on the one hand, and our general partner and its direct and indirect owners, on the other hand, which include BIP and its co-investors. The resolution of these conflicts may not always be in our best interest or that of our shareholders.

Our partnership agreement replaces our general partner's fiduciary duties to holders of our Class A shares with contractual standards governing its duties.

Our partnership agreement contains provisions that eliminate the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law and replaces those duties with several different contractual standards. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, free of any duties to us and our shareholders other than the implied contractual covenant of good faith and fair dealing. This provision entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our shareholders. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate business opportunities among us and its affiliates;
- whether to exercise its limited call right;
- whether to seek approval of the resolution of a conflict of interest by the conflicts committee of the board of directors of our general partner;
- how to exercise its voting rights with respect to the units it owns; and
- whether or not to consent to any merger, consolidation or conversion of the partnership or amendment to the partnership agreement.

In addition, our partnership agreement provides that any construction or interpretation of our partnership agreement and any action taken pursuant thereto or any determination, in each case, made by our general partner in good faith, shall be conclusive and binding on all shareholders.

By purchasing shares, you agree to become bound by the provisions in the partnership agreement, including the provisions discussed above.

Our partnership agreement restricts the remedies available to holders of our Class A shares for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to shareholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement provides that:

- whenever our general partner, the board of directors of our general partner or any committee thereof (including the conflicts committee) makes a determination or takes, or declines to take, any other action in their respective capacities, our general partner, the board of directors of our general partner and any committee thereof (including the conflicts committee), as applicable, is required to make such determination, or take or decline to take such other action, in good faith, meaning that it subjectively believed that the decision was in the best interests of our partnership, and, except as specifically provided by our partnership agreement, will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;
- our general partner will not have any liability to us or our shareholders for decisions made in its capacity as a general partner so long as such decisions are made in good faith;

- our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and
- our general partner will not be in breach of its obligations under the partnership agreement (including any duties to us or our shareholders) if a transaction with an affiliate or the resolution of a conflict of interest is:
 - approved by the conflicts committee of the board of directors of our general partner (although our general partner is not obligated to seek such approval);
 - approved by the vote of a majority of the outstanding voting shares, excluding any shares owned by our general partner and its affiliates;
 - determined by the board of directors of our general partner to be on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
 - determined by the board of directors of our general partner to be fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner or the conflicts committee must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our shareholders or the conflicts committee and the board of directors of our general partner determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in the last two bullets above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership challenging such determination, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Our general partner's affiliates may compete with us.

Our partnership agreement provides that our general partner is restricted from engaging in any business activities other than acting as our general partner and those activities incidental to its ownership of interests in us. The restrictions contained in our general partner's limited liability company agreement are subject to a number of exceptions. For example, affiliates of our general partner, including BIP, the Sponsor Entities, and their respective affiliates and owners, are not prohibited from engaging in other businesses or activities that might be in direct competition with us.

Our general partner has a call right that may require you to sell your Class A shares at an undesirable time or price.

If at any time more than 80% of our outstanding shares (including Class A shares issuable upon the exchange of Class B shares) are owned by our general partner or its affiliates, our general partner has the right (which it may assign to any of its affiliates or to us), but not the obligation, to acquire all, but not less than all, of the remaining Class A shares held by public shareholders at a price equal to the greater of (x) the highest cash price paid by our general partner or its affiliates for any shares purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those shares and (y) the current market price calculated in accordance with our partnership agreement as of the date three business days before the date the notice is mailed. As a result, you may be required to sell your Class A shares at an undesirable time or price and may not receive any return of or on your investment. You may also incur a tax liability upon a sale of your Class A shares.

Tax Risks

The tax treatment of TEP depends on it not being subject to a material amount of entity-level taxation by individual states. If TEP becomes subject to material additional amounts of entity-level taxation for state tax purposes, it would reduce the amount of cash available for dividends to us and increase the portion of our dividends treated as taxable dividends.

We own a 63.75% membership interest in Tallgrass Equity as of February 12, 2020, which directly and indirectly owns all of the partnership interests in TEP. Accordingly, the value of our indirect investment in TEP, as well as the anticipated after-tax economic benefit of an investment in our Class A shares, depends largely on TEP being treated as a partnership for income tax purposes.

Several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of such a tax on TEP by any state will reduce the cash available for distributions to TEP unitholders, likely causing a substantial reduction in the value of our Class A shares.

We may incur substantial corporate income tax liabilities on our allocable share of TEP income.

We are classified as a corporation for U.S. federal income tax purposes and, in most states in which TEP does business, for state income tax purposes. To the extent that TEP allocates to us net taxable income in any year, current law provides that we will be subject to U.S. federal income tax at a rate of 21%, and to state income tax at rates that vary from state to state. The amount of cash available for dividends to you will be reduced by the amount of any such income taxes payable by us for which we establish reserves.

Compliance with and changes in tax laws could adversely affect our performance.

We are subject to extensive tax laws and regulations, including federal and state income tax laws and transactional tax laws such as excise, sales/use, payroll, franchise and ad valorem tax laws. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted that could result in increased tax expenditures in the future. Further, taxing authorities may change their application of existing taxes, so that additional entities or transactions may become subject to an existing tax. Many of these tax liabilities are subject to audits by the respective taxing authority. These audits may result in additional tax payments, as well as interest and penalties. In one such audit for a tax period from May 1, 2014 through April 30, 2015, the Ohio Tax Commissioner began assessing Rockies Express a public utility excise tax on transactions concerning product that entered and exited the Rockies Express Pipeline with the State of Ohio. Rockies Express disputed its obligation to pay Ohio's public utility excise tax under the relevant Ohio statute, but made payments in the amounts assessed for the 2015 tax period and subsequent tax periods in order to preserve its right to appeal. On February 11, 2020, the Ohio Supreme Court reached a final decision adverse to the position taken by Rockies Express. As a result, Rockies Express no longer anticipates receiving a refund of the prior payments made to the State of Ohio and expects to continue to be required to pay this tax in future tax periods. These excise taxes will reduce the cash available for dividends to our Class A shareholders, and any additional tax payments, interest and penalties that are successfully assessed by a taxing authority in the future as a result of an audit or otherwise, will also reduce the cash available for dividends to our Class A shareholders.

If the IRS makes audit adjustments to TEP's income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from TEP, in which case TEP may require its unitholders and former unitholders to reimburse it for such taxes (including any applicable penalties or interest) or, if TEP is required to bear such payment, TEP's cash available for distribution to TEP's unitholders might be substantially reduced.

If the IRS makes audit adjustments to TEP's income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from TEP. TEP will generally have the ability to shift any such tax liability to its general partner and its unitholders in accordance with their interests in TEP during the year under audit, but there can be no assurance that TEP will be able to (or will choose to) do so under all circumstances. If TEP is required to make payments of taxes, penalties and interest resulting from audit adjustments, it may require its unitholders and former unitholders to reimburse it for such taxes (including any applicable penalties or interest) or, if TEP is required to bear such payment, its cash available for distribution to its unitholders might be substantially reduced.

Taxable gain or loss on the sale of our Class A shares could be more or less than expected.

If a holder sells our Class A shares, the holder will recognize a gain or loss equal to the difference between the amount realized and the holder's tax basis in those Class A shares. To the extent that the amount of our dividends exceeds our current and accumulated earnings and profits as determined for U.S. federal income tax purposes, the dividends will be treated as a tax-free return of capital and will reduce a holder's tax basis in the Class A shares. Because our dividends in excess of our earnings and profits decrease a holder's tax basis in Class A shares, such excess dividends will result in a corresponding increase in the amount of gain, or a corresponding decrease in the amount of loss, recognized by the holder upon the sale of the Class A shares.

Our current tax treatment may change, which could affect the value of our Class A shares or reduce our cash available for dividends.

Changes in U.S. federal income tax law relating to our tax treatment as a corporation could result in (i) our being subject to additional taxation at the entity level with the result that we would have less cash available for dividends and (ii) a greater portion of our dividends being treated as taxable dividends. Moreover, we are subject to tax in numerous jurisdictions. Changes in current law in these jurisdictions, particularly relating to the treatment of deductions attributable to acquisitions of interests in Tallgrass Equity, could result in our being subject to additional taxation at the entity level with the result that we would have less cash available for dividends.

Any decrease in our Class A share price could adversely affect our amount of cash available for dividends.

Changes in certain market conditions may cause our Class A share price to decrease. If the Exchange Right Holders exercise their Exchange Right when our Class A share price is less than the price at which the Class A shares were sold in the TGE IPO, the ratio of our income tax deductions to gross income would decline. This decline could result in our being subject to tax sooner than expected, our tax liability being greater than expected, or a greater portion of our dividends being treated as taxable dividends.

The IRS Form 1099-DIV that you receive from your broker may over-report your dividend income with respect to our shares for U.S. federal income tax purposes, and failure to report your dividend income in a manner consistent with the IRS Form 1099-DIV that you receive from your broker may cause the IRS to assert audit adjustments to your U.S. federal income tax return. If you are a non-U.S. holder of our shares, your broker or other withholding agent may overwithhold taxes from dividends paid to you, in which case you generally would have to timely file a U.S. tax return or an appropriate claim for refund in order to claim a refund of the overwithheld taxes.

Dividends we pay with respect to our Class A shares will constitute "dividends" for U.S. federal income tax purposes only to the extent of our current and accumulated earnings and profits as determined for U.S. federal income tax purposes. Dividends we pay in excess of our earnings and profits will not be treated as "dividends" for U.S. federal income tax purposes; instead, they will be treated first as a tax-free return of capital to the extent of your tax basis in your shares and then as capital gain realized on the sale or exchange of such shares. We may be unable to timely determine the portion of our dividends that is a "dividend" for U.S. federal income tax purposes.

If you are a U.S. holder of our Class A shares, the IRS Form 1099-DIV may not be consistent with our determination of the amount that constitutes a "dividend" to you for U.S. federal income tax purposes or you may receive a corrected IRS Form 1099-DIV (and you may therefore need to file an amended federal, state or local income tax return). For example, we provided a corrected IRS Form 1099-DIV to applicable shareholders in August 2019 for dividends paid in 2018 following further review and revision of our initial estimates used to provide the original IRS Form 1099-DIV in February 2019. We will attempt to timely notify you of available information to assist you with your income tax reporting (such as posting the correct information on our website). However, the information that we provide to you may be inconsistent with the amounts reported to you by your broker on IRS Form 1099-DIV, and the IRS may disagree with any such information and may make audit adjustments to your tax return.

If you are a non-U.S. holder of our Class A shares, "dividends" for U.S. federal income tax purposes will be subject to withholding of U.S. federal income tax at a 30% rate (or such lower rate as may be specified by an applicable income tax treaty) unless the dividends are effectively connected with your conduct of a U.S. trade or business. In the event that we are unable to timely determine the portion of our dividends that is a "dividend" for U.S. federal income tax purposes, or your broker or withholding agent chooses to withhold taxes from dividends in a manner inconsistent with our determination of the amount that constitutes a "dividend" for such purposes, your broker or other withholding agent may overwithhold taxes from dividends paid to you. In such a case, you generally would have to timely file a U.S. tax return or an appropriate claim for refund in order to obtain a refund of the overwithheld tax.

We expect that our ability to use net operating losses arising prior to the TEP Merger to offset future income will be limited as a result of the TEP Merger, and our ability to use net operating losses arising after the TEP Merger to offset future income may be limited.

We expect that our ability to use any net operating losses ("NOLs") generated by us prior to the TEP Merger to offset future income will be limited due to experiencing an "ownership change" as defined under Section 382 of the Code, as a result of the TEP Merger. Our ability to use NOLs arising after the TEP Merger to offset future income may be substantially limited if we were to experience another ownership change.

In general, an ownership change occurs if our "5-percent shareholders," as defined under Section 382 of the Code, including certain groups of persons treated as 5-percent shareholders, collectively increased their ownership in Class A shares by more than 50 percentage points over a rolling three-year period. An ownership change can occur as a result of a public offering of Class A shares, as well as through secondary market purchases of Class A shares and certain types of reorganization transactions. As a result of the exchange of TEP common units for Class A shares in the TEP Merger, we expect that the TEP Merger caused us to experience an ownership change.

A corporation (including any entity such as us that is treated as a corporation for U.S. federal income tax purposes) that experiences an ownership change will generally be subject to an annual limitation on the use of its pre-ownership change NOLs (and certain other losses and credits) equal to the equity value of the corporation immediately before the ownership change, multiplied by the long-term tax-exempt rate (as determined by the Internal Revenue Service) for the month in which the ownership change occurs. Such a limitation could, for any given year, have the effect of increasing the amount of our U.S. federal income tax liability, which would negatively impact the amount of after-tax cash available for dividends to holders of Class A shares and our financial condition.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

A description of our properties is contained in Item 1.—Business, "Our Assets" of this Annual Report.

Our principal executive offices are located at 4200 W. 115th Street, Suite 350, Leawood, KS 66211 and our telephone number is 913-928-6060.

We own two office buildings in Lakewood, Colorado, with a portion being leased to a third party pursuant to a lease with an initial term through March 2020. In addition, we lease our principal executive offices in Leawood, Kansas.

Item 3. Legal Proceedings

See Note 20 – *Legal and Environmental Matters*, which is incorporated by reference into this Part I—Item 3 of this Annual Report.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Market Information

Our Class A shares are listed on the NYSE under the symbol "TGE." Our Class B shares are not listed or traded on any stock exchange.

Holders

As of February 10, 2020, there were 81 shareholders of record of our Class A shares. This number does not include shareholders whose shares are held in trust by other entities. The actual number of beneficial shareholders is greater than the number of holders of record. In addition, as of February 10, 2020, 6 shareholders of record owned all 102,136,875 of our Class B shares.

Equity Compensation Plan

See Item 12.—Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters for information regarding our Equity Compensation Plan.

Distributions of Available Cash

General. Our partnership agreement requires that, within 55 days after the end of each quarter, we distribute our available cash to Class A shareholders of record on the applicable record date. As further discussed in Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations, "Dividends," pursuant to the Take-Private Merger Agreement, TGE has agreed not to pay dividends during the pendency of the transactions contemplated by the Take-Private Merger Agreement.

Definition of Available Cash. Available cash is defined in our partnership agreement and generally means, with respect to any calendar quarter, all cash and cash equivalents on hand at the date of determination of available cash for the distribution in respect of such quarter (including expected distributions from Tallgrass Equity in respect of such quarter), less the amount of cash reserves established by our general partner, which are not subject to a cap, to, among other things:

- comply with applicable law;
- comply with any agreement binding upon us or our subsidiaries (exclusive of TEP and its subsidiaries);
- provide for future capital expenditures, debt service and other credit needs as well as any federal, state, provincial or other income tax that may affect us in the future; or
- otherwise provide for the proper conduct of our business.

Our available cash includes cash on hand resulting from borrowings made after the end of the quarter.

Our Sources of Available Cash. Our sole cash-generating asset is an approximate 63.75% membership interest in Tallgrass Equity. Tallgrass Equity's sole cash generating assets consist of its direct and indirect equity interests in its subsidiaries and unconsolidated affiliates, including its 75% membership interest in Rockies Express. Therefore, our cash flow and resulting ability to make distributions will be completely dependent upon the ability of Tallgrass Equity's subsidiaries and unconsolidated affiliates to make distributions.

The actual amount of cash that Tallgrass Equity's subsidiaries and unconsolidated affiliates, and correspondingly Tallgrass Equity, will have available for distribution will primarily depend on the amount of cash Tallgrass Equity's subsidiaries and unconsolidated affiliates generate from their operations. For a description of factors that may impact our results, please read "Item 1A.—Risk Factors."

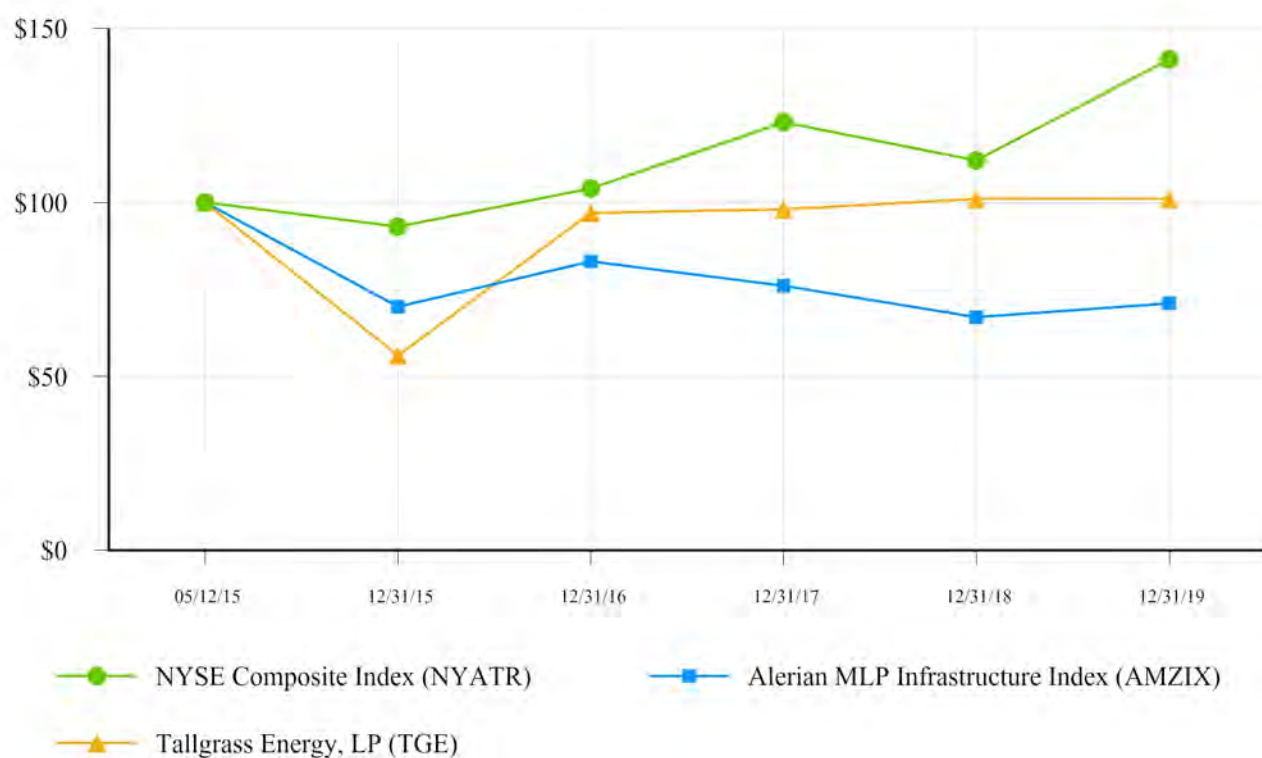
In addition, the actual amount of cash that Tallgrass Equity will have available for distribution will depend on other factors, some of which are beyond our control, including:

- the level of revenue Tallgrass Equity's subsidiaries and unconsolidated affiliates are able to generate from their respective businesses;
- the level of capital expenditures Tallgrass Equity's subsidiaries and unconsolidated affiliates make;
- the level of Tallgrass Equity's subsidiaries and unconsolidated affiliates' operating, maintenance and general and administrative expenses or related obligations;
- the cost of acquisitions, if any;

- Tallgrass Equity's subsidiaries and unconsolidated affiliates' debt service requirements and other liabilities;
- Tallgrass Equity's subsidiaries and unconsolidated affiliates' working capital needs;
- restrictions on distributions contained in Tallgrass Equity's subsidiaries and unconsolidated affiliates' debt agreements and any future debt agreements;
- Tallgrass Equity's subsidiaries and unconsolidated affiliates' ability to borrow under their existing revolving credit agreements to make distributions; and
- the amount, if any, of cash reserves established by our general partner, in its sole discretion, for the proper conduct of our business.

Performance Graph

The following performance graph compares the performance of our Class A shares with the NYSE Composite Index Total Return and the Alerian MLP Infrastructure Index Total Return during the period beginning on May 12, 2015, and ending on December 31, 2019. The graph assumes a \$100 investment in our Class A shares and in each of the indices at the beginning of the period and a reinvestment of distributions/dividends paid on such investments throughout the period.



Recent Sales of Unregistered Equity Securities

None.

Repurchase of Equity by Tallgrass Energy, LP or Affiliated Purchasers

None.

Item 6. Selected Financial Data

The historical financial statements included in this Annual Report reflect the consolidated results of operations of TGE's membership interest in Tallgrass Equity and Tallgrass Equity's membership interest in TEP. In connection with the closing of the TGE IPO on May 12, 2015, the following transactions (the "Reorganization Transactions") occurred (i) Tallgrass Equity distributed its interests in Tallgrass Energy Holdings and Tallgrass Energy Holdings distributed its existing limited partner interest in TGE, respectively, to certain of the Exchange Right Holders, that also collectively own 100% of the voting power of Tallgrass Energy Holdings; (ii) TGE issued 47,725,000 Class A shares to the public (including 6,225,000 Class A shares issued in connection with the underwriters' exercise of the overallotment option) for net proceeds of approximately \$1.3 billion; (iii) the existing limited partner interests in TGE held by certain of the Exchange Right Holders were converted into 115,729,440 Class B shares, 6,225,000 of which were automatically cancelled in connection with the underwriters' exercise of its overallotment option; (iv) Tallgrass Equity issued 41,500,000 TE Units to TGE in exchange for approximately \$1.1 billion in net proceeds from the issuance of TGE's Class A shares to the public and amended the limited liability company agreement of Tallgrass Equity to, among other things, provide that TGE is the managing member of Tallgrass Equity; (v) TGE used the net proceeds from the purchase of the 6,225,000 overallotment option shares to purchase a like amount of TE Units from certain of the Exchange Right Holders; and (vi) Tallgrass Equity entered into a \$150 million revolving credit facility and borrowed \$150 million thereunder, using the aggregate proceeds from such borrowings, together with the net proceeds from the TGE IPO that Tallgrass Equity received from TGE, to purchase 20 million TEP common units from Tallgrass Development, LP at \$47.68 per TEP common unit (the "Acquired TEP Units") and pay offering expenses and other transaction costs. Tallgrass Equity distributed the remaining proceeds (the "Excess Proceeds") to certain of the Exchange Right Holders. The following discussion analyzes the financial condition and results of operations of TGE, which for periods prior to the completion of the TGE IPO on May 12, 2015 includes the financial condition and results of operations of TGE Predecessor, which refers to TGE as recast to show the effects of the Reorganization Transactions.

In addition, the historical financial statements included in this Annual Report reflect operations of Terminals and NatGas, which were acquired effective January 1, 2017. In certain circumstances and for ease of reading we discuss the financial results of these entities prior to their respective acquisitions as being "our" financial results during historic periods, although Terminals and NatGas were owned by TD from November 13, 2012 to December 31, 2016. As used in this Annual Report, unless the context otherwise requires, "we," "us," "our," the "Partnership," "TGE" and similar terms refer to Tallgrass Energy, LP, together with its consolidated subsidiaries (including Tallgrass Equity, TEP and their respective subsidiaries). The term our "general partner" refers to Tallgrass Energy GP, LLC. References to "Tallgrass Development" or "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 consolidated financial statements and related notes thereto included elsewhere in this Annual Report. A reference to a "Note" herein refers to the accompanying Notes to Consolidated Financial Statements contained in Item 8.—Financial Statements. In addition, please read "Cautionary Statement Regarding Forward-Looking Statements" and "Risk Factors" for information regarding certain risks inherent in our business.

The following table shows selected historical financial and operating data of TGE for the periods and as of the dates indicated. The selected historical financial data for periods prior to the completion of the TGE IPO on May 12, 2015 includes the financial condition and results of operations of TGE Predecessor, which refers to TGE as recast to show the effects of the Reorganization Transactions.

We derived the information in the following table from, and that information should be read together with and is qualified in its entirety by reference to, the consolidated financial statements and the accompanying notes included elsewhere in this Annual Report.

Our operating results incorporate a number of significant estimates and uncertainties. Such matters could cause the data included herein to not be indicative of our future financial condition or results of operations. A discussion of our critical accounting estimates is included in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7.

	Year Ended December 31,				
	2019	2018	2017	2016	2015
Statement of operations data:	(in thousands, except per share amounts)				
Revenue.....	\$ 868,548	\$ 793,259	\$ 655,898	\$ 611,662	\$ 542,661
Operating income.....	\$ 352,760	\$ 350,631	\$ 271,847	\$ 258,418	\$ 206,229
Equity in earnings of unconsolidated investments ⁽¹⁾	\$ 325,385	\$ 306,819	\$ 237,110	\$ 54,531	\$ 2,759
Net income before tax	\$ 519,148	\$ 523,380	\$ 432,443	\$ 267,780	\$ 193,071
Net income	\$ 448,555	\$ 467,671	\$ 223,985	\$ 250,039	\$ 200,348
Net income (loss) attributable to TGE, excluding predecessor operations interest.....	\$ 248,809	\$ 137,127	\$ (128,729)	\$ 26,794	\$ 24,563 ⁽²⁾
Basic net income (loss) per Class A share	\$ 1.42	\$ 1.27	\$ (2.22)	\$ 0.55	\$ 0.51 ⁽²⁾
Diluted net income (loss) per Class A share	\$ 1.42	\$ 1.27	\$ (2.22)	\$ 0.55	\$ 0.51 ⁽²⁾
Balance sheet data (at end of period):					
Property, plant and equipment, net	\$ 2,774,518	\$ 2,802,429	\$ 2,394,337	\$ 2,079,232	\$ 2,079,567
Unconsolidated investments ⁽¹⁾	\$ 2,006,219	\$ 1,861,686	\$ 909,531	\$ 475,625	\$ 13,565
Total assets	\$ 6,214,086	\$ 5,893,509	\$ 4,292,013	\$ 3,625,480	\$ 3,088,635
Long-term debt, net.....	\$ 3,441,024	\$ 3,205,958	\$ 2,292,993	\$ 1,555,981	\$ 901,000
Other:					
Dividends declared per Class A share..	\$ 1.62 ⁽³⁾	\$ 2.02	\$ 1.35	\$ 1.00	\$ 0.39

⁽¹⁾ For more information see Note 7 – *Investments in Unconsolidated Affiliates*.

⁽²⁾ The net income attributed to TGE was based upon the number of days between the closing of the IPO on May 12, 2015 to December 31, 2015.

⁽³⁾ As a result of the Take-Private Merger Agreement discussed in Note 1 – *Description of Business*, TGE has agreed not to pay dividends during the pendency of the transaction contemplated by the agreement. Therefore, no dividends have been declared for the three months ended December 31, 2019.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the consolidated financial statements and related notes thereto included elsewhere in this Annual Report. The discussion and analysis for the year ended December 31, 2018 compared to the year ended December 31, 2017 can be found in our Annual Report on Form 10-K for the year ended December 31, 2018 and should be read in conjunction with the discussion and analysis below.

Overview

TGE is a limited partnership that owns, operates, acquires and develops midstream energy assets in North America and has elected to be treated as a corporation for U.S. federal income tax purposes.

Our operations are conducted through, and our operating assets are owned by, our direct and indirect subsidiaries, including Tallgrass Equity, in which we directly own an approximate 63.75% membership interest as of February 12, 2020. We 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 an integrated natural gas storage facility;
- Crude Oil Transportation—the ownership and operation of FERC-regulated crude oil pipeline systems; 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.

Additional information about our operations and assets is contained in the business overview included in Item 1.—Business under "*Overview*" and "*Our Assets*."

Summary of Results for the Year Ended December 31, 2019

Net income for the year ended December 31, 2019 was \$448.6 million, with Adjusted EBITDA and Cash Available for Dividends (each as defined below under "Non-GAAP Financial Measures") of \$996.3 million and \$798.2 million, respectively, compared to net income for the year ended December 31, 2018 of \$467.7 million, with Adjusted EBITDA and Cash Available for Dividends of \$654.4 million and \$548.7 million, respectively. The decrease in net income and the increase in Adjusted EBITDA and Cash Available for Dividends was largely driven by our increased ownership in TEP due to the TEP Merger.

Recent Developments

Take Private Proposal

As discussed in Item 1.—Business, "*Organizational Structure*," on December 16, 2019, we and our general partner entered into the Take-Private Merger Agreement pursuant to which the Take-Private Merger will occur. At the Effective Time, each issued and outstanding Class A share other than the Class A shares owned by the Sponsor Entities and certain of their permitted transferees, will be converted into the right to receive \$22.45 per Class A share in cash without any interest thereon. Through the Take-Private Merger, the Sponsor Entities and the limited partners of Buyer immediately prior to the Effective Time will become the owners of all of the outstanding Class A shares and the Class A shares will cease to be publicly traded upon closing of the Take-Private Merger.

The Take-Private Merger Agreement is subject to the satisfaction of customary conditions, including approval of the merger by holders of a majority of the outstanding Class A and Class B shares of TGE, voting together as a single class, inclusive of the approximately 44.1% of the total Class A and Class B shares held by the Sponsors Entities as of December 31, 2019. As discussed further in Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations, "*Dividends*," pursuant to the Take-Private Merger Agreement, TGE has agreed not to pay dividends during the pendency of the transactions contemplated by the Take-Private Merger Agreement.

Rockies Express Senior Notes Offerings

On January 31, 2020, Rockies Express issued \$750 million in aggregate principal amount of senior notes. The issuance was composed of two tranches, \$400 million of 3.60% senior notes due 2025 and \$350 million of 4.80% senior notes due 2030. The proceeds of the issuance will be used to redeem the 5.625% senior notes due April 15, 2020 in March 2020.

Factors and Trends Impacting Our Business

We expect to continue to be affected by certain key factors and trends described below. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about, or interpretations of, available information prove to be incorrect, our actual results may vary materially from our expected results. See also Item 1A.—Risk Factors.

Long-Term U.S. Crude Oil and Natural Gas Prospects

Crude oil, natural gas, and products derived from both continue to be critical components of energy supply and demand in the United States. Crude oil and natural gas prices have declined and experienced significant volatility in recent years. While there have been periods of stability in crude oil and natural gas prices during that time, price declines and volatility may continue to occur in commodity markets in the future. Despite this volatility, we believe long-term prospects for continued domestic crude oil and natural gas production increases are favorable.

We believe long-term growth will be driven, in part, by a combination of increased domestic demand resulting from population and economic growth, higher industrial consumption in the U.S. spurred by the lower commodity price of feedstock and fuel, and a desire to reduce domestic reliance on imports. One example is that we expect natural gas to gradually displace coal-fired electricity generation due to the low prices of natural gas and stricter environmental regulations on the mining and

burning of coal. Additionally, we believe that the U.S. will continue to increase its total volume exported of both natural gas and crude oil as new and additional infrastructure is developed to export these commodities. We expect productivity of oil and natural gas wells to continue increasing over the long-term in some basins across the United States because of the increasing precision and efficiency of horizontal drilling and hydraulic fracturing in oil and natural gas extraction. We also believe there is a substantial inventory of drilled but uncompleted wells in the basins we serve, including the Bakken shale and Denver-Julesburg basin, that are likely to be completed and turned into production as commodity prices stabilize and continue to recover.

Current Commodity Environment

During the last several years, prices of crude oil, natural gas, and NGLs have experienced periods of price stability as well as periods of decline and significant volatility. To the extent some of our customers remain concerned about extended unfavorably low prices as has been experienced with sustained lower natural gas prices throughout 2019, it may be due to concerns over excess supply, truncation of current OPEC production cuts and increased mainstream use of alternative sources of energy.

Demand for our services depends, in part, on the development of additional natural gas and crude oil reserves by third parties. This requires significant capital expenditures by others to install facilities that extract natural gas and crude oil. However, the possibility for low commodity prices may result in a lack of available capital for these types of expenditures. To the extent our customers cannot finance these activities, we expect they may be less likely to enter into demand based, long-term firm fee contracts. Low commodity prices may also negatively impact the financial condition of our customers and could impact their ability to meet their financial obligations to us.

Additionally, lower commodity prices may lead to reduced utilization of our assets. For example, reduced utilization could result in increased deficiency balances held by customers of our Pony Express System. For additional information, see Item 1A.—Risk Factors, *"The Throughput and Deficiency Agreements for the Pony Express System and some of our service agreements with respect to our water business services contain provisions that can reduce the cash flow stability that the agreements were designed to achieve."* and *"Any significant decrease in available supplies of hydrocarbons in our areas of operation, or redirection of existing hydrocarbon supplies to other markets, could adversely affect our business and operating results. Persistent low commodity prices could result in lower throughput volumes and reduced cash flows."*

Growth Associated with Acquisitions and Expansion Projects

Growth associated with acquisitions

We believe that we are well-positioned to grow through accretive acquisitions due to our stable financial profile and diverse asset base that presents many logical strategic opportunities. In the past, we heavily relied on acquiring assets from TD's portfolio of midstream assets. Now that TD has divested its entire asset portfolio, our growth through acquisitions will rely almost exclusively on buying assets or businesses from third parties. Third party acquisitions present different risks than those associated with acquiring assets from TD. Sourcing attractive, accretive opportunities and performing diligence on those opportunities requires significantly more time from our employees. Most third party acquisitions involve competition from other buyers, which generally increases the purchase price. If we are able to execute a third-party transaction, we may encounter challenges when integrating different work cultures and operational systems. During 2019, we executed several third party acquisitions and joint ventures, including the acquisition of CES and the Powder River Gateway joint venture with Silver Creek. For additional information, see Note 3 – *Acquisitions and Dispositions*.

Growth associated with expansion projects

We also believe that we are well positioned to increase volumes to our systems through cost-effective capacity expansions and other methods for improving efficiency. For example, in 2019, Powder River Gateway placed the Iron Horse Pipeline in-service and we continued to execute the development and construction of the Cheyenne Hub Enhancement Project at Rockies Express and the Cheyenne Connector Pipeline with our joint venture partner DCP. In 2018, Pony Express placed the Platteville Extension Project in-service and in 2017, Rockies Express placed in-service the Zone 3 Capacity Enhancement Project, which added an incremental 0.8 Bcf/d of east-to-west capacity within Zone 3 of the Rockies Express Pipeline.

Energy Capital Markets and Interest Rates

In recent years, investors have required higher yields on our Class A shares, which has led to decreased prices and limited our ability to complete equity offerings at favorable pricing. As a result, we have had to alter financing strategies and rely primarily on debt issuances and internally generated cash flow to fund growth capital expenditures and acquisitions. In 2017 and 2018, TEP was able to issue an additional \$1.6 billion in aggregate principal amount of senior notes with rates from 4.75% to 5.5%. In 2019 and 2020, Rockies Express was able to issue an additional \$1.3 billion in aggregate principal amount of senior notes with rates from 3.60% to 4.95%. For additional information regarding the impact of changes in interest rates on our existing debt, please read Item 7A.—Quantitative and Qualitative Disclosures About Market Risk.

How We Evaluate Our Operations

We evaluate our results using, among other measures, contract profile and volumes, operating costs and expenses, Adjusted EBITDA and Cash Available for Dividends. Adjusted EBITDA and Cash Available for Dividends 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, recycling 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 operating costs and expenses that we evaluate include cost of sales, cost of transportation services, operations and maintenance and general and administrative costs. Operating expenses are driven primarily by expenses related to the operation, maintenance and growth of our asset base.

Adjusted EBITDA and Cash Available for Dividends

Adjusted EBITDA and Cash Available for Dividends 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 midstream infrastructure companies, 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 dividends to our shareholders;
- our ability to incur and service debt and fund capital expenditures; and
- the viability of acquisitions and other capital expenditure projects and the returns on investment of various expansion and growth opportunities.

We believe that the presentation of Adjusted EBITDA and Cash Available for Dividends provides useful information to investors in assessing our financial condition and results of operations. Adjusted EBITDA and Cash Available for Dividends 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 Cash Available for Dividends be considered alternatives to available cash or other definitions in our partnership agreement. Adjusted EBITDA and Cash Available for Dividends 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 Cash Available for Dividends may be defined differently by other companies in our industry, our definition of Adjusted EBITDA and Cash Available for Dividends 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 and deficiency payments received from or utilized by our customers. We also use Cash Available for Dividends, which we generally define as Adjusted EBITDA, less cash interest costs, maintenance capital expenditures, current income tax, and certain cash reserves permitted by our governing documents. Adjusted EBITDA and Cash Available for Dividends are both calculated and presented at the Tallgrass Equity level, before consideration of noncontrolling interest associated with the Exchange Right Holders or calculating distributions from Tallgrass Equity to us, on one hand, and to the Exchange Right Holders, on the other. We believe calculating these measures at Tallgrass Equity provides investors the most complete and comparable picture of our overall financial and operational results and provides a consistent metric for period over period comparisons that is not impacted by any future exercises by the Exchange Right Holders of the Exchange Right, which does not have a dilutive effect on TGE's net income per share.

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.

Adjusted EBITDA and Cash Available for Dividends are not presentations made in accordance with GAAP. The following table presents a reconciliation of Adjusted EBITDA to Net income (loss) attributable to TGE and net cash provided by operating activities and a reconciliation of Cash Available for Dividends to net cash provided by operating activities, the most directly comparable GAAP financial measures, for each of the periods indicated:

	Year Ended December 31,		
	2019	2018	2017
	(in thousands)		
Reconciliation of Tallgrass Equity Adjusted EBITDA to Net income (loss) attributable to TGE			
Net income (loss) attributable to TGE	\$ 248,809	\$ 137,127	\$ (128,729)
Add:			
Interest expense, net ⁽¹⁾	161,429	95,465	29,403
Depreciation and amortization expense ⁽¹⁾	127,503	74,998	26,131
Distributions from unconsolidated investments ⁽¹⁾	470,981	302,364	86,551
Deficiency payments, net ⁽¹⁾	16,992	14,443	7,701
Non-cash compensation expense ⁽¹⁾⁽²⁾	31,563	8,634	2,682
Loss on debt retirement	—	2,245	—
Income tax expense ⁽¹⁾	70,578	55,709	208,458
Net income attributable to Exchange Right Holders.....	193,961	208,618	137,849
Less:			
Equity in earnings of unconsolidated investments ⁽¹⁾	(325,385)	(237,197)	(66,922)
Other non-cash (gain)	(724)	—	—
Loss (gain) on disposal of assets ⁽¹⁾	354	(4,630)	(189)
Non-cash loss (gain) related to derivative instruments ⁽¹⁾	272	(3,340)	64
(Gain) on remeasurement of unconsolidated investment ⁽¹⁾	—	—	(2,744)
Tallgrass Equity Adjusted EBITDA.....	<u>\$ 996,333</u>	<u>\$ 654,436</u>	<u>\$ 300,255</u>
Reconciliation of Tallgrass Equity Adjusted EBITDA and Cash Available for Dividends to Net Cash Provided by Operating Activities			
Net cash provided by operating activities	\$ 679,006	\$ 672,525	\$ 571,396
Add:			
Interest expense, net ⁽¹⁾	161,429	95,465	29,403
Other, including changes in operating working capital ⁽¹⁾	155,898	(113,554)	(300,544)
Tallgrass Equity Adjusted EBITDA	<u>\$ 996,333</u>	<u>\$ 654,436</u>	<u>\$ 300,255</u>
Less:			
Cash interest cost ⁽¹⁾	(155,174)	(91,590)	(27,669)
Maintenance capital expenditures, net ⁽¹⁾	(42,287)	(14,176)	(4,179)
Current income tax expense ⁽¹⁾	(672)	—	—
Tallgrass Equity Cash Available for Dividends.....	<u>\$ 798,200</u>	<u>\$ 548,670</u>	<u>\$ 268,407</u>

⁽¹⁾ Net of noncontrolling interest associated with less than wholly-owned subsidiaries of Tallgrass Equity.

⁽²⁾ Represents TGE's portion of non-cash compensation expense related to Equity Participation Shares and TEP's Equity Participation Units, excluding amounts allocated to Tallgrass Development prior to the TD Merger 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:

	Year Ended December 31,		
	2019	2018	2017
	(in thousands)		
Reconciliation of Tallgrass Equity Adjusted EBITDA to Operating Income in the Natural Gas Transportation Segment ⁽¹⁾			
Operating income.....	\$ 66,200	\$ 69,586	\$ 67,434
Add:			
Depreciation and amortization expense ⁽²⁾	19,773	13,102	5,421
Distributions from unconsolidated investments ⁽²⁾	458,739	297,496	85,994
Less:			
Other, net ⁽²⁾	(1,205)	2,359	1,424
Adjusted EBITDA attributable to noncontrolling interests.....	—	(5,319)	20,738
Non-cash (gain) related to derivative instruments ⁽²⁾	—	—	(33)
Tallgrass Equity Segment Adjusted EBITDA.....	<u>\$ 543,507</u>	<u>\$ 377,224</u>	<u>\$ 180,978</u>
Reconciliation of Tallgrass Equity Adjusted EBITDA to Operating Income in the Crude Oil Transportation Segment ⁽¹⁾			
Operating income.....	\$ 273,303	\$ 258,308	\$ 190,170
Add:			
Depreciation and amortization expense ⁽²⁾	55,699	36,578	16,156
Deficiency payments, net ⁽²⁾	9,867	4,858	7,967
Distributions from unconsolidated investments.....	5,464	—	—
Less:			
Adjusted EBITDA attributable to noncontrolling interests.....	—	(60,414)	(73,385)
Non-cash (gain) related to derivative instruments ⁽²⁾	—	—	(123)
Tallgrass Equity Segment Adjusted EBITDA.....	<u>\$ 344,333</u>	<u>\$ 239,330</u>	<u>\$ 140,785</u>
Reconciliation of Tallgrass Equity Adjusted EBITDA to Operating Income in the Gathering, Processing & Terminalling Segment ⁽¹⁾			
Operating income.....	\$ 60,787	\$ 51,565	\$ 33,453
Add:			
Depreciation and amortization expense ⁽²⁾	48,730	21,665	4,554
Non-cash loss (gain) related to derivative instruments ⁽²⁾	272	(3,340)	750
Distributions from unconsolidated investments ⁽²⁾	6,778	4,868	557
Deficiency payments, net ⁽²⁾	9,356	8,540	(458)
Loss (gain) on disposal of assets ⁽²⁾	354	(4,630)	(189)
Other, net ⁽²⁾	1,384	182	142
Less:			
Other non-cash (gain).....	(724)	—	—
Adjusted EBITDA attributable to noncontrolling interests.....	(5,778)	(19,647)	(22,726)
Tallgrass Equity Segment Adjusted EBITDA.....	<u>\$ 121,159</u>	<u>\$ 59,203</u>	<u>\$ 16,083</u>
Total Tallgrass Equity Segment Adjusted EBITDA.....	<u>\$ 1,008,999</u>	<u>\$ 675,757</u>	<u>\$ 337,846</u>
Corporate general and administrative costs	(12,666)	(21,321)	(37,591)
Total Tallgrass Equity Adjusted EBITDA.....	<u>\$ 996,333</u>	<u>\$ 654,436</u>	<u>\$ 300,255</u>

⁽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 21 – *Reportable Segments* to the accompanying consolidated financial statements.

- (2) Net of noncontrolling interest associated with less than wholly-owned subsidiaries of Tallgrass Equity.

Results of Operations

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

	Year Ended December 31,		
	2019	2018	2017
	(in thousands, except operating data)		
Natural Gas Transportation Segment:			
TIGT and Trailblazer average firm contracted volumes (MMcf/d) ⁽¹⁾ ...	1,850	1,636	1,711
Rockies Express average firm contracted volumes (MMcf/d) ⁽²⁾	4,101	4,101	4,101
Crude Oil Transportation Segment:			
Pony Express average contracted capacity (Bbbls/d).....	311,101	306,936	301,936
Pony Express average throughput (Bbbls/d)	358,442	336,314	267,734
Gathering, Processing & Terminalling Segment:			
Natural gas processing inlet volumes (MMcf/d)	118	122	109
Freshwater average volumes (Bbbls/d)	52,133	17,849	69,139
Produced water gathering and disposal average volumes (Bbbls/d)	182,292	98,489	31,511

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

(2) Volumes contracted under long-term firm fee contracts.

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

	Year Ended December 31,		
	2019	2018	2017
	(in thousands)		
Revenues:			
Crude oil transportation services	\$ 417,106	\$ 398,334	\$ 345,733
Natural gas transportation services	129,620	126,894	122,364
Sales of natural gas, NGLs, and crude oil	171,729	168,586	108,503
Processing and other revenues	150,093	99,445	79,298
Total Revenues	868,548	793,259	655,898
Operating Costs and Expenses:			
Cost of sales	94,816	114,815	91,213
Cost of transportation services	63,258	53,068	46,200
Operations and maintenance	88,474	72,460	62,069
Depreciation and amortization	128,825	110,862	90,800
General and administrative	104,373	70,656	65,536
Taxes, other than income taxes	35,669	31,810	28,832
Loss (gain) on disposal of assets	373	(11,043)	(599)
Total Operating Costs and Expenses	515,788	442,628	384,051
Operating Income	352,760	350,631	271,847
Other Income (Expense):			
Equity in earnings of unconsolidated investments	325,385	306,819	237,110
Interest expense, net	(161,407)	(133,319)	(89,348)
Other income (expense), net	2,410	(751)	12,834
Total Other Income (Expense)	166,388	172,749	160,596
Net income before tax	519,148	523,380	432,443
Income tax expense	(70,593)	(55,709)	(208,458)
Net income	448,555	467,671	223,985
Net income attributable to noncontrolling interests	(199,746)	(330,544)	(352,714)
Net income (loss) attributable to TGE	\$ 248,809	\$ 137,127	\$ (128,729)

Year Ended December 31, 2019 Compared to the Year Ended December 31, 2018

Revenues. Total revenues were \$868.5 million for the year ended December 31, 2019 compared to \$793.3 million for the year ended December 31, 2018, which represents an increase of \$75.3 million, or 9%, in total revenues. The overall increase in revenue was largely driven by increased revenues of \$56.2 million and \$42.2 million in the Gathering, Processing & Terminalling and Crude Oil Transportation segments, respectively, partially offset by a \$22.4 million increase in eliminations of intersegment revenue and decreased revenues of \$0.7 million in the Natural Gas Transportation segment, as discussed further below.

Operating costs and expenses. Operating costs and expenses were \$515.8 million for the year ended December 31, 2019 compared to \$442.6 million for the year ended December 31, 2018, which represents an increase of \$73.2 million, or 17%. The overall increase in operating costs and expenses was driven by increased operating costs and expenses of \$47.0 million, \$27.2 million, and \$2.7 million in the Gathering, Processing & Terminalling, Crude Oil Transportation, and Natural Gas Transportation segments, respectively, partially offset by decreased operating costs and expenses of \$3.7 million in the Corporate and Other segment. The decrease in Corporate and Other expenses was primarily driven by a \$22.4 million increase in eliminations of intersegment operating costs and expenses, partially offset by a \$20.2 million increase in corporate general and administrative costs due to an increase in equity-based compensation costs related to the accelerated vesting of certain Equity Participation Shares as a result of the March 2019 Blackstone Acquisition and other events that occurred in 2019.

Equity in earnings of unconsolidated investments. Equity in earnings of unconsolidated investments was \$325.4 million and \$306.8 million for the years ended December 31, 2019 and 2018, respectively. Equity in earnings of unconsolidated investments of \$325.4 million for the year ended December 31, 2019 primarily reflects our portion of earnings and the \$34.0 million of amortization of a negative basis difference associated with our aggregate 75% membership interest in Rockies Express, as well as equity in earnings related to our 51% membership interests in Pawnee Terminal and Powder River Gateway of \$5.9 million and \$3.1 million, respectively. Equity in earnings of unconsolidated investments of \$306.8 million for the year ended December 31, 2018 primarily reflects our portion of earnings and the \$35.9 million of amortization of a negative basis difference associated with our aggregate 75% membership interest in Rockies Express, inclusive of the additional 25.01% membership interest acquired in February 2018, as well as \$4.2 million of equity in earnings related to our 51% membership interest in Pawnee Terminal. The overall increase was primarily driven by a \$13.0 million increase in equity in earnings from Rockies Express as a result of lower interest expense due to the repayment of Rockies Express' \$550 million of 6.85% senior notes due July 15, 2018 and the refinancing of Rockies Express' \$525 million of 6.00% senior notes due January 15, 2019, the additional 25.01% membership interest acquired in February 2018, and the proceeds from the contract termination discussed in Note 20 – *Legal and Environmental Matters*. These increases were partially offset by lower west-end revenue as a result of contract expirations and the tax expense recognized during the year ended December 31, 2019 as a result of the Ohio Supreme Court decision discussed in Note 20 – *Legal and Environmental Matters*.

Interest expense, net. Interest expense of \$161.4 million for the year ended December 31, 2019 was primarily composed of interest and fees associated with the Senior Notes and TEP revolving credit facility, as defined in Note 10 – *Long-term Debt*. Interest expense of \$133.3 million for the year ended December 31, 2018 was primarily composed of interest and fees associated with the TEP and Tallgrass Equity revolving credit facilities and the 2024 Notes and 2028 Notes, as defined in Note 10 – *Long-term Debt*. The increase in interest and fees is primarily due to increased borrowings to fund a portion of our 2018 and 2019 acquisitions and a special contribution to Rockies Express to fund our pro rata portion of the repayment of Rockies Express' \$550 million of 6.85% senior notes due July 15, 2018, as well as the higher borrowing rate on the 2023 Notes, the proceeds of which were used to repay borrowings under the revolving credit facility.

Other income (expense), net. Other income (expense), net typically includes rental income and other income related to capital costs incurred to build new connections to our systems. Other income for the year ended December 31, 2019 was \$2.4 million compared to other expense of \$0.8 million for the year ended December 31, 2018. Other expense of \$0.8 million for the year ended December 31, 2018 also included a \$2.2 million loss on debt retirement associated with the write off of deferred financing costs associated with the Amendment to the TEP revolving credit facility and the termination of the Tallgrass Equity revolving credit facility.

Income tax expense. Income tax expense for the year ended December 31, 2019 was \$70.6 million, compared to income tax expense of \$55.7 million for the year ended December 31, 2018. The increase in income tax expense was primarily due to our increased ownership in TEP effective June 30, 2018 as a result of the TEP Merger and the exercise of the Exchange Right effective March 11, 2019 and the resulting increase in income allocated to TGE.

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⁾	Year Ended December 31,		
	2019	2018	2017
	(in thousands)		
Revenues:			
Natural gas transportation services	\$ 131,799	\$ 131,555	\$ 129,058
Sales of natural gas, NGLs, and crude oil	542	1,195	3,412
Processing and other revenues	7,411	7,709	8,551
Total revenues.....	139,752	140,459	141,021
Operating costs and expenses:			
Cost of sales	1,218	1,382	2,767
Cost of transportation services	1,940	2,990	2,852
Operations and maintenance	28,734	27,185	28,910
Depreciation and amortization	19,773	19,442	19,180
General and administrative	16,962	15,279	15,385
Taxes, other than income taxes	4,925	4,595	4,493
Total operating costs and expenses	73,552	70,873	73,587
Operating income.....	\$ 66,200	\$ 69,586	\$ 67,434

⁽¹⁾ Segment results as presented represent total revenue and operating income, including intersegment activity. For reconciliations to the consolidated financial data, see Note 21 – *Reportable Segments*.

Year Ended December 31, 2019 Compared to the Year Ended December 31, 2018

Revenues. Natural Gas Transportation segment revenues were \$139.8 million for the year ended December 31, 2019 compared to \$140.5 million for the year ended December 31, 2018, which represents a decrease of \$0.7 million in segment revenues driven by a \$0.7 million decrease in sales of natural gas due to decreased volumes sold and lower natural gas prices.

Operating costs and expenses. Operating costs and expenses in the Natural Gas Transportation segment were \$73.6 million for the year ended December 31, 2019 compared to \$70.9 million for the year ended December 31, 2018, which represents an increase of \$2.7 million, or 4%. The overall increase in operating costs and expenses was primarily due to a \$1.7 million increase in general and administrative costs driven by an increase in labor costs and a \$1.5 million increase in operations and maintenance costs driven by increased pipeline integrity work.

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⁾	Year Ended December 31,		
	2019	2018	2017
	(in thousands)		
Revenues:			
Crude oil transportation services.....	\$ 474,987	\$ 437,653	\$ 353,395
Sales of natural gas, NGLs, and crude oil.....	10,830	6,290	11,179
Processing and other revenues	830	511	—
Total revenues.....	486,647	444,454	364,574
Operating costs and expenses:			
Cost of sales	11,025	8,334	9,680
Cost of transportation services	80,122	68,184	57,284
Operations and maintenance	15,321	12,896	11,838
Depreciation and amortization	55,699	54,237	52,364
General and administrative	24,059	18,486	20,906
Taxes, other than income taxes	27,118	24,009	22,332
Total operating costs and expenses	213,344	186,146	174,404
Operating income.....	\$ 273,303	\$ 258,308	\$ 190,170

⁽¹⁾ Segment results as presented represent total revenue and operating income, including intersegment activity. For reconciliations to the consolidated financial data, see Note 21 – *Reportable Segments*.

Year Ended December 31, 2019 Compared to the Year Ended December 31, 2018

Revenues. Crude Oil Transportation segment revenues were \$486.6 million for the year ended December 31, 2019 compared to \$444.5 million for the year ended December 31, 2018, which represents an increase of \$42.2 million, or 9%, in segment revenues driven by a \$37.3 million increase in crude oil transportation services and a \$4.5 million increase in sales of crude oil due to increased volumes sold, partially offset by lower crude oil prices during the year ended December 31, 2019. The increase in crude oil transportation services revenue was primarily due to a \$19.2 million increase in walk-up shipper revenue and a \$17.2 million increase in committed shipper revenues, both driven by increased throughput volumes and the FERC annual index adjustments effective July 1, 2018 and 2019.

Operating costs and expenses. Operating costs and expenses in the Crude Oil Transportation segment were \$213.3 million for the year ended December 31, 2019 compared to \$186.1 million for the year ended December 31, 2018, which represents an increase of \$27.2 million, or 15%. The overall increase in operating costs and expenses was primarily due to a \$11.9 million increase in cost of transportation services driven by higher throughput volumes during the year ended December 31, 2019 compared to the year ended December 31, 2018, resulting in higher costs for drag reducing agents and pump station electrical costs as well as increased terminalling costs, a \$5.6 million increase in general and administrative costs driven by an increase in insurance and labor costs, a \$3.1 million increase in taxes, other than income taxes driven by an increase in property tax assessment estimates, a \$2.7 million increase in cost of sales due to increased volumes sold partially offset by lower crude oil prices, and a \$2.4 million increase in operations and maintenance costs driven by increased pipeline integrity work.

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⁾	Year Ended December 31,		
	2019	2018	2017
	(in thousands)		
Revenues:			
Sales of natural gas, NGLs, and crude oil	\$ 160,357	\$ 161,101	\$ 93,998
Processing and other revenues	175,538	118,564	92,213
Total revenues.....	335,895	279,665	186,211
Operating costs and expenses:			
Cost of sales	82,981	105,985	80,088
Cost of transportation services	74,534	52,327	20,650
Operations and maintenance	44,419	32,379	21,321
Depreciation and amortization	50,052	32,369	19,256
General and administrative	19,123	12,877	10,035
Taxes, other than income taxes	3,626	3,206	2,007
Loss (gain) on disposal of assets.....	373	(11,043)	(599)
Total operating costs and expenses	275,108	228,100	152,758
Operating income.....	\$ 60,787	\$ 51,565	\$ 33,453

⁽¹⁾ Segment results as presented represent total revenue and operating income, including intersegment activity. For reconciliations to the consolidated financial data, see Note 21 – *Reportable Segments*.

Year Ended December 31, 2019 Compared to the Year Ended December 31, 2018

Revenues. Gathering, Processing & Terminalling segment revenues were \$335.9 million for the year ended December 31, 2019 compared to \$279.7 million for the year ended December 31, 2018, which represents a \$56.2 million, or 20%, increase in segment revenues. The increase in segment revenues was due to a \$57.0 million increase in processing and other revenues, partially offset by a \$0.7 million decrease in sales of natural gas, NGLs, and crude oil. The increase in processing and other revenues was driven by (i) increased water business services revenue of \$50.0 million driven by the consolidation of BNN Colorado in December 2018, the acquisitions of NGL Water Solutions Bakken in November 2018 and CES in May 2019, and increased produced water disposal and fresh water transportation volumes and (ii) increased terminal services revenue of \$5.7 million driven by the Buckingham Terminal expansion, the Natoma Terminal placed into service in April 2018, the Grasslands Terminal placed into service in August 2019, and increased throughput on the Pony Express System. The decrease in sales of natural gas, NGLs, and crude oil was driven by decreased sales of NGLs of \$33.1 million, primarily due to lower NGL prices partially offset by higher volumes sold, partially offset by increased crude oil sales of \$26.1 million at Stanchion and increased sales of natural gas of \$6.4 million due to higher volumes sold, partially offset by lower natural gas prices.

Operating costs and expenses. Operating costs and expenses in the Gathering, Processing & Terminalling segment were \$275.1 million for the year ended December 31, 2019 compared to \$228.1 million for the year ended December 31, 2018, which represents an increase of \$47.0 million, or 21%. The increase in operating costs and expenses was primarily driven by (i) an increase of \$22.2 million in the cost of transportation services due to crude oil transportation fees and the acquisitions of BNN North Dakota in January 2018 and NGL Water Solutions Bakken in November 2018, (ii) increases of \$17.7 million, \$12.0 million, and \$6.2 million in depreciation and amortization, operations and maintenance, and general and administrative costs, respectively, each primarily due to acquisitions and assets placed into service in 2018 and 2019 at Water Solutions and Terminals, and (iii) \$0.4 million loss on the disposal of assets during the year ended December 31, 2019, compared to the \$11.0 million gain on disposal of assets, primarily driven by the gain on disposal of Tallgrass Crude Gathering during the year ended December 31, 2018. These increases were partially offset by a \$23.0 million decrease in cost of sales. The decrease in cost of sales was driven by lower NGL prices, partially offset by higher volumes processed, increased settlements to producers as a result of higher sales of residue gas from the Douglas Gathering System, and the consolidation of BNN Colorado in December 2018 and the acquisitions of BNN North Dakota in January 2018 and NGL Water Solutions Bakken in November 2018.

Liquidity and Capital Resources Overview

Our primary sources of liquidity for the year ended December 31, 2019 were cash generated from operations and borrowings under our revolving credit facility. 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 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 by TEP to Tallgrass Equity during the pendency of the transactions contemplated by the Take-Private Merger Agreement. For additional information regarding our planned cash distributions, see Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations, "Dividends." We believe that future internal growth projects or potential acquisitions will be funded primarily through a combination of cash generated from operations, borrowings under our revolving credit facility and issuances of debt securities. For additional information regarding our revolving credit facility and senior unsecured notes, see Note 10 – *Long-term Debt*. For additional information regarding our equity transactions, see Note 11 – *Partnership Equity*.

Our total liquidity as of December 31, 2019 and 2018 was as follows:

	December 31, 2019	December 31, 2018
	(in thousands)	
Cash on hand ⁽¹⁾	\$ 9,394	\$ 9,596
Total capacity under the revolving credit facility	2,250,000	2,250,000
Less: Outstanding borrowings under the revolving credit facility	(1,456,000)	(1,224,000)
Less: Letters of credit issued under the revolving credit facility	(94)	(94)
Available capacity under the revolving credit facility	793,906	1,025,906
Total liquidity	<u>\$ 803,300</u>	<u>\$ 1,035,502</u>

⁽¹⁾ Includes cash on hand at TGE and its consolidated subsidiaries.

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 December 31, 2019, we had a working capital deficit of \$131.8 million compared to a working capital deficit of \$146.9 million at December 31, 2018, which represents an increase in working capital of \$15.1 million. The overall increase in working capital was primarily attributable to changes in the following components:

- an increase in accounts receivable of \$88.2 million primarily due to crude oil sales at Stanchion and related party receivables related to construction costs paid on behalf of joint ventures; and
- an increase in inventories of \$14.8 million primarily due to crude oil purchases at Stanchion.

These working capital increases were partially offset by:

- an increase in accounts payable and accrued liabilities of \$72.5 million primarily due to crude oil purchases at Stanchion, an increase in employee compensation accruals, and an increase in the provision for rate refunds at Trailblazer, partially offset by lower capital accruals; and
- an increase in deferred revenue of \$16.8 million primarily from deficiency payments collected by Pony Express and Water Solutions.

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:

	Year Ended December 31,		
	2019	2018	2017
	(in thousands)		
Net cash provided by (used in):			
Operating activities	\$ 679,006	\$ 672,525	\$ 571,396
Investing activities	\$ (287,284)	\$ (987,212)	\$ (898,541)
Financing activities	\$ (391,924)	\$ 321,690	\$ 327,279

Year Ended December 31, 2019 Compared to the Year Ended December 31, 2018

Operating Activities. Cash flows provided by operating activities were \$679.0 million and \$672.5 million for the years ended December 31, 2019 and 2018, respectively. The increase in net cash flows provided by operating activities of \$6.5 million was primarily driven by a \$19.1 million increase in distributions received from unconsolidated affiliates, primarily Rockies Express, as well as the increase in operating results, as discussed above. These increases were partially offset by a net decrease in cash flows from changes in working capital driven by an increase in net cash outflows from other current assets and liabilities, primarily due to crude oil inventory purchases at Stanchion.

Investing Activities. Cash flows used in investing activities were \$287.3 million for the year ended December 31, 2019, primarily driven by:

- capital expenditures of \$285.7 million, primarily due to Pony Express expansion projects, Cheyenne Connector prior to the deconsolidation of Cheyenne Connector in November 2019, and additional natural gas gathering infrastructure;
- contributions to unconsolidated investments in the amount of \$115.5 million, primarily to fund our share of capital projects at Rockies Express, Powder River Gateway, and Cheyenne Connector;
- net cash outflows of \$48.4 million for the acquisition of CES; and
- cash outflows of \$37.0 million for the initial capital contribution and formation of the Powder River Gateway joint venture.

These cash outflows were partially offset by cash inflows of:

- \$145.0 million of distributions received from unconsolidated investments in excess of cumulative earnings recognized, primarily from Rockies Express; and
- \$59.7 million from the sale of a 50% membership interest in Cheyenne Connector.

Cash flows used in investing activities were \$987.2 million for the year ended December 31, 2018, primarily driven by:

- contributions to unconsolidated investments in the amount of \$473.9 million, primarily to fund our portion of the repayment of Rockies Express' \$550 million of 6.85% senior notes due July 15, 2018, as well as to fund our share of capital projects at Iron Horse and BNN Colorado;
- capital expenditures of \$368.9 million, primarily due to spending on the Cheyenne Connector, additional water gathering infrastructure located in North Dakota, a 55-mile extension on the Pony Express System, construction of the Buckingham Terminal expansion, construction of the Guernsey, Natoma, and Grasslands Terminals, and pipe replacement and remediation work on the Trailblazer Pipeline system as discussed in Note 20 – *Legal and Environmental Matters*;
- cash outflows of \$95.0 million for the acquisition of BNN North Dakota;
- cash outflows of \$91.0 million for the acquisition of NGL Water Solutions Bakken;
- cash outflows of \$30.7 million for the initial capital contribution and formation of PLT;
- cash outflows of \$30.6 million for the acquisition of a 51% membership interest in Pawnee Terminal; 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:

- \$80.2 million of distributions received from unconsolidated affiliates in excess of cumulative earnings recognized, primarily from Rockies Express; and
- \$50.0 million from the sale of Tallgrass Crude Gathering.

Financing Activities. Cash flows used in financing activities were \$391.9 million for the year ended December 31, 2019, primarily driven by:

- dividends paid to Class A shareholders of \$371.6 million;
- distributions to noncontrolling interests of \$237.4 million, consisting of Tallgrass Equity distributions to the Exchange Right Holders of \$229.9 million and distributions to Deeprock Development, BNN West Texas, and BNN Colorado noncontrolling interests of \$7.5 million; and
- tax payments funded by shares tendered by employees to satisfy tax withholding obligations of \$16.2 million related to the issuance of Class A shares under our LTIP plan.

These cash outflows were partially offset by net borrowings under the revolving credit facility of \$232.0 million.

Cash flows provided by financing activities were \$321.7 million for the year ended December 31, 2018, primarily driven by:

- proceeds from TEP's issuance of \$500.0 million in aggregate principal amount of 2023 Notes; and
- net borrowings under the revolving credit facilities of \$417.0 million.

These cash inflows were partially offset by cash outflows of:

- distributions to noncontrolling interests of \$327.6 million, which consisted of Tallgrass Equity distributions to the Exchange Right Holders of \$223.7 million, distributions to TEP unitholders of \$97.7 million, and distributions to Deeprock Development and Pony Express noncontrolling interests of \$6.2 million;
- dividends paid to Class A shareholders of \$206.4 million; and
- cash outflows of \$50.0 million for the acquisition of an additional 2% membership interest in Pony Express.

Dividends

Dividends to our Class A shareholders. We distribute 100% of TGE's available cash at the end of each quarter to Class A shareholders of record beginning with the quarter ended June 30, 2015. Available cash at TGE is generally defined in our partnership agreement as all cash and cash equivalents on hand at the date of determination in respect of such quarter less reserves established in the discretion of our general partner for future requirements. For a discussion of factors and trends impacting our business, which in turn impacts our ability to pay dividends to our Class A shareholders, please see "*Factors and Trends Impacting Our Business*" above.

As a result of the Take-Private Merger Agreement, TGE has agreed to not pay dividends with respect to its Class A shares and to not permit Tallgrass Equity to pay any distributions on its TE Units during the pendency of the transactions contemplated by the Take-Private Merger Agreement, in each case, without the prior written consent of Buyer. Therefore, no dividends have been declared for the three months ended December 31, 2019. However, in the event the Take-Private Merger Agreement is terminated, the board of directors of our general partner will promptly fix a record date and declare and pay a dividend to the holders of Class A shares in an amount equal to the amount of dividends that otherwise would have been paid during the pendency of the transactions contemplated by the Take-Private Merger Agreement, all in accordance with our partnership agreement.

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 typically include acquisitions or capital improvements (such as additions to or improvements on the capital assets owned, or acquisition or construction of new capital assets).

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. We expect to incur approximately \$130 million for expansion capital projects and approximately \$40 million for maintenance capital expenditures in 2020. The following table summarizes the maintenance and expansion capital expenditures incurred at our consolidated entities:

	Year Ended December 31,		
	2019	2018	2017
	(in thousands)		
Maintenance capital expenditures	\$ 42,417	\$ 20,956	\$ 14,822
Expansion capital expenditures	230,832	353,672	135,604
Total capital expenditures incurred	<u>\$ 273,249</u>	<u>\$ 374,628</u>	<u>\$ 150,426</u>

Capital expenditures incurred represent capital expenditures paid and accrued during the period. Maintenance capital expenditures were \$42.4 million for the year ended December 31, 2019 compared to \$21.0 million for the year ended December 31, 2018. 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 \$230.8 million for the year ended December 31, 2019 compared to \$353.7 million for the year ended December 31, 2018. Expansion capital expenditures for the year ended December 31, 2019 consisted primarily of spending on the Pony Express expansion, Cheyenne Connector prior to the deconsolidation of the project in November 2019, and additional natural gas gathering infrastructure. Expansion capital expenditures for the year ended December 31, 2018 consisted primarily of spending on the Cheyenne Connector, additional water gathering infrastructure located in North Dakota, PLT, a 55-mile extension on the Pony Express System, construction of the Buckingham Terminal expansion, construction of the Guernsey, Natoma, and Grasslands Terminals, and pipe replacement and remediation work on the Trailblazer Pipeline system as discussed in Note 20 – *Legal and Environmental Matters*.

During the years ended December 31, 2019, 2018, and 2017, we invested cash of \$115.5 million, \$473.9 million, and \$45.9 million, respectively, in unconsolidated affiliates, including Rockies Express, Powder River Gateway, Cheyenne Connector subsequent to the deconsolidation in November 2019, Iron Horse prior to our contribution of Iron Horse to the Powder River Gateway joint venture in January 2019, and BNN Colorado prior to our consolidation of BNN Colorado in December 2018, to fund our share of capital projects, including a special contribution of approximately \$412.5 million to fund our portion of the repayment of Rockies Express' \$550 million of 6.85% senior notes due July 15, 2018. In addition, we have made commitments of approximately \$60 million to fund our portion of capital costs at Cheyenne Connector subsequent to closing of the joint venture in the fourth quarter of 2019.

As discussed in "*Dividends*," TGE has agreed not to pay dividends during the pendency of the transaction contemplated by the Take-Private Merger Agreement.

Contractual Obligations

Following is a summary of our contractual cash obligations in future periods, representing amounts that were fixed and determinable as of December 31, 2019:

Contractual Obligations	Payments Due By Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
	(in thousands)				
Debt obligations ⁽¹⁾	\$ 3,456,000	\$ —	\$ 1,456,000	\$ 1,250,000	\$ 750,000
Interest on debt obligations ⁽²⁾	732,698	155,143	281,534	170,667	125,354
Operating lease obligations ⁽³⁾	20,329	2,247	2,582	1,856	13,644
Finance lease obligations ⁽⁴⁾	19,567	449	898	917	17,303
Service contracts and other purchase commitments ⁽⁵⁾	81,302	41,329	12,754	6,964	20,255
Total	<u>\$ 4,309,896</u>	<u>\$ 199,168</u>	<u>\$ 1,753,768</u>	<u>\$ 1,430,404</u>	<u>\$ 926,556</u>

- (1) Debt obligations at December 31, 2019 consisted of borrowings under the revolving credit facility and the Senior Notes. For additional information, see Note 10 – *Long-term Debt*.
- (2) Interest on debt obligations is estimated using current borrowings and interest rates as of December 31, 2019. For additional information, see Note 10 – *Long-term Debt*.
- (3) Operating leases consist of leases for crude oil storage and terminalling, office space, and equipment. For additional information, see Note 13 – *Leases*.
- (4) Finance lease obligations consist of the PLT land site lease. For additional information, see Note 13 – *Leases*.
- (5) Other purchase commitments primarily relate to service contracts, right-of-way contracts, planned non-reimbursable capital expenditures, and operating and maintenance expenditures. For additional information, see Note 14 – *Commitments & Contingent Liabilities*.

All of our employees are employed by Tallgrass Management, LLC ("Tallgrass Management"), a wholly-owned subsidiary of Tallgrass Equity. As a result, the costs of employer and director compensation and benefits are incurred directly by Tallgrass Equity.

Prior to July 1, 2018, Tallgrass Management was a wholly-owned subsidiary of Tallgrass Energy Holdings. In connection with the closing of the TEP initial public offering on May 17, 2013, TEP and TEP GP entered into an Omnibus Agreement with Tallgrass Energy Holdings and certain of its affiliates (the "TEP Omnibus Agreement"). The TEP Omnibus Agreement provided 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. In addition, in connection with the closing of the TGE initial public offering on May 12, 2015 (the "TGE IPO"), TGE entered into an Omnibus Agreement (the "TGE Omnibus Agreement") with Tallgrass Energy GP, LLC (formerly known as TEGP Management, LLC), Tallgrass Equity and Tallgrass Energy Holdings. The TEP Omnibus Agreement and TGE Omnibus Agreement were terminated effective March 11, 2019 in connection with the closing of the March 2019 Blackstone Acquisition.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Critical Accounting Estimates

Our significant accounting policies and the anticipated impact of recently issued accounting standards are described in Note 2 – *Summary of Significant Accounting Policies*. Management's discussion and analysis of financial condition and results of operations are based upon our financial statements, which have been prepared in accordance with GAAP. The preparation of these financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosure of contingent assets and liabilities. The accounting policies discussed below are considered by management to be critical to an understanding of our financial statements as their application places the most significant demands on management's judgment. Due to the inherent uncertainties involved with this type of judgment, actual results could differ significantly from estimates and may have a material adverse impact on our results of operations, equity or cash flows. For additional information concerning our other accounting policies, please read the notes to the financial statements included in this report.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Business Combinations		
<i>For each acquired entity we estimate the fair value of the assets acquired and liabilities assumed based on their estimated fair values at the date of acquisition. If the initial accounting for the business combination is incomplete when the combination occurs, an estimate will be recorded. We recognize intangible assets separately from goodwill if those assets are determined to exist. Any excess of the purchase price over the fair value of the net tangible and identifiable intangible assets acquired, as well as noncontrolling interest, if applicable, is recognized as goodwill.</i>	We measure the fair value of assets acquired and liabilities assumed in business combinations using widely accepted valuation techniques, such as the income, cost, and market approaches. These types of analyses require us to make assumptions and estimates regarding industry and economic factors and the profitability of future business strategies. These analyses require management to apply significant judgment in estimating future cash flows as well as fair values of individual assets, including forecasting useful lives of the assets, assessing the probability of different outcomes, including anticipated volumes, contract renewals and changes in our regulated rates, and selecting the discount rate that reflects the risk inherent in future cash flows.	If estimates or assumptions used to estimate the fair value of acquired assets, liabilities assumed, and noncontrolling interests are materially incorrect, the fair values assigned to assets acquired and liabilities assumed could significantly differ. Such a difference would impact future earnings through depreciation and amortization expense. In addition, if forecasts supporting the valuation of the long-lived assets or goodwill are not achieved, impairments could arise. Further, if customer relationships terminate prior to the expected useful life, we will be required to record a charge to operations to write-off any remaining unamortized balance of the intangible asset assigned to that customer.
Impairment of Long-lived Assets		
<i>We periodically evaluate whether the carrying value of long-lived assets has been impaired when circumstances indicate the carrying value of those assets may not be recoverable. If we conclude an asset group needs to be tested for recoverability, this evaluation is based on undiscounted cash flow projections expected to be realized over the remaining useful life of the primary asset. The carrying amount is not recoverable if it exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset's carrying value over its fair value.</i>	We review our long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Our impairment analyses require management to apply judgment in the determination of whether circumstances indicate a recoverability test should be performed, and if so, in estimating future cash flows as well as asset fair values, including forecasting useful lives of the assets, assessing the probability of different outcomes, including anticipated volumes, contract renewals and changes in our regulated rates. If the asset group fails the recoverability test, we generally determine its respective fair value using an income approach, and therefore must select a discount rate that reflects the risk inherent in future cash flows. However, we may use other commonly accepted techniques to estimate fair value.	Using the impairment review methodology described herein, we have not recorded any impairment charges on long-lived assets during the year ended December 31, 2019. If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to an impairment charge. A prolonged period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future impairment due to the potential impact on our operations and cash flows.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Business Combinations		
Impairment of Goodwill		
<i>We evaluate goodwill for impairment annually in the third quarter, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount.</i>	We use either the qualitative assessment option or proceed directly to the quantitative impairment test depending on facts and circumstances of the reporting unit, including the last time we performed a quantitative assessment of fair value and the excess of that fair value over carrying value, changes in the business and overall economic environment, and factors specific to the respective reporting unit. If a quantitative assessment is performed we may estimate the fair value of the reporting unit using an income approach, which requires estimates and judgments around the forecasted useful lives of the assets, the probability of different outcomes, anticipated volumes, contract renewals, changes in our regulated rates, forecasts of commodity prices and the discount rate that reflects the risk inherent in future cash flows. We may also use a market approach to estimate the fair value of the reporting unit. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, and estimated future cash flows, including an estimate of operating and general and administrative costs. It is our policy to conduct impairment testing based on our current business strategy in light of present industry and economic conditions, as well as future expectations.	If our assumptions are not appropriate, or future events indicate that our goodwill is impaired, our net income would be impacted by the amount by which the carrying value exceeds the fair value of the reporting unit, to the extent of the balance of goodwill. A prolonged period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future goodwill impairment for reporting units due to the potential impact on our operations and cash flows. We completed our impairment testing of goodwill in the third quarter of 2019 using the methodology described herein, and determined there was no impairment. Approximately \$79.2 million of goodwill is allocated to the Midstream Facilities reporting unit, which is a component of our Gathering, Processing & Terminalling segment. As a result of current market conditions, certain producers from which the Midstream Facilities reporting unit receives natural gas for processing have recently indicated that they currently expect to deliver lower volumes than previously anticipated. The results of the Midstream Facilities reporting unit's impairment testing as of August 31, 2019 indicate that the fair value of the reporting unit exceeds the carrying value by approximately 17%. As a result, no impairment charge was recorded. However our analysis includes assumptions related to the discount rate used to discount future cash flows, and reflects a gradual recovery of commodity prices and a corresponding increase in volumes over time. This reporting unit is sensitive to changes in the discount rate, as such increases in the discount rate, could result in a future impairment. Additionally, if our outlook is not realized, or our producers further decrease volumes, we may recognize an impairment in the future.
Revenue Recognition		
<i>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 exercising their rights and recognize revenue associated with contract liabilities when the probability becomes remote that the customer will exercise its remaining rights.</i>	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 requires management to apply judgment in contract renewal assumptions, along with the accounting for the renewal given the facts and circumstances of each contract, estimating future system capacity and the ability of our customers to utilize that capacity.	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 could be impacted and we may experience material changes in revenue.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

For the year ended December 31, 2019, the percentage of our firm fee, volumetric fee, and commodity exposed Adjusted EBITDA was 86%, 7%, and 7%, respectively. Historically, we have had a limited amount of direct commodity price exposure related to 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, and other, 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 year ended December 31, 2019, TMID represented 3% 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 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 December 31, 2019, assuming a parallel shift in the forward curve:

	Fair Value	Effect of 10% Price Increase	Effect of 10% Price Decrease
		(in thousands)	
Crude oil derivative contract assets ⁽¹⁾	\$ 2,536	\$ —	\$ —
Crude oil derivative contract liabilities ⁽¹⁾	\$ 60	\$ (3,619)	\$ 3,619

⁽¹⁾ Represents the net forward sale of 593,000 barrels of crude oil in our Gathering, Processing & Terminalling segment which will settle throughout 2020.

Interest Rate Risk

As of December 31, 2019, TEP has issued \$2.0 billion of Senior Notes and has a \$2.25 billion revolving credit facility with outstanding borrowings of \$1.46 billion. Borrowings under TEP's 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 0.25% to 1.25% for base rate borrowings and 1.25% to 2.25% for reserve adjusted Eurodollar rate borrowings, based upon TEP's total leverage ratio.

We do not currently hedge the interest rate risk on TEP's 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 \$0.8 million based on our outstanding debt under the revolving credit facility as of December 31, 2019.

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, prepayments, guarantees or other 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 serve 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 December 31, 2019.

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

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Board of Directors of Tallgrass Energy GP, LLC, the general partner of Tallgrass Energy, LP, and the shareholders of Tallgrass Energy, LP

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Tallgrass Energy, LP and subsidiaries (the "Partnership") as of December 31, 2019, the related consolidated statements of income, equity, and cash flows for the year ended December 31, 2019, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2019, and the results of its operations and its cash flows for the year ended December 31, 2019, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Partnership's internal control over financial reporting as of December 31, 2019, based on the criteria established in the *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 12, 2020, expressed an unqualified opinion on the Partnership's internal control over financial reporting.

Change in Accounting Principle

As discussed in Notes 2 and 13 to the financial statements, the Partnership has changed its method of accounting for leases in the year ended December 31, 2019 due to adoption of Accounting Standards Codification Topic 842 - *Leases*.

Basis for Opinion

These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's financial statements based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audit included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audit provides a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing separate opinions on the critical audit matter or on the accounts or disclosures to which it relates.

Goodwill - Midstream Facilities Reporting Unit - Refer to Notes 2 and 8 to the financial statements

Critical Audit Matter Description

The Partnership evaluates goodwill for impairment on an annual basis and whenever events or changes in circumstances necessitate an evaluation for impairment. When goodwill is evaluated for impairment using a quantitative test, the Partnership compares the fair value of the reporting unit with its respective book value, including goodwill, using an income approach based on a discounted cash flow analysis. Estimating the fair value of a reporting unit using the income approach requires management to make various assumptions and estimates, including the weighted-average cost of capital. Unpredictable events or deteriorating market or operating conditions could result in a future change to the discounted cash flow models, causing impairments in the future. The goodwill balance was \$441.4 million as of December 31, 2019, of which \$79.2 million was allocated to the Midstream Facilities Reporting Unit ("MFRU"). The fair value of MFRU exceeded its carrying value by 17% as of the measurement date and, therefore, no impairment was recognized.

Given the significant judgments made by management to estimate the fair value of MFRU and the difference between its fair value and carrying value, performing audit procedures to evaluate the reasonableness of management's assumptions and estimates related to selection of the weighted-average cost of capital, specifically due to the sensitivity of the valuation of MFRU to changes in the weighted-average cost of capital, required a high degree of auditor judgment and an increased extent of effort, including the need to involve our fair value specialists.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the weighted-average cost of capital used by management to estimate the fair value of MFRU included the following, among others:

- We tested the effectiveness of controls over management's goodwill impairment evaluation, including those over the assumptions used in selecting the weighted-average cost of capital.
- With the assistance of our fair value specialists, we evaluated the reasonableness of the weighted-average cost of capital by:
 - Evaluating the appropriateness of the mathematical model used to develop the weighted-average cost of capital.
 - Recomputing the mathematical accuracy of the calculation of the weighted-average cost of capital.
 - Evaluating the guideline public companies selected by management and used in the selection of the weighted-average cost of capital considering the comparability of operations to MFRU.
 - Comparing the selected weighted-average cost of capital to weighted-average cost of capital estimates published by a third-party financial institution for subject entities within MFRU's industry.
 - Developing a range of independent estimates of the weighted-average cost of capital by independently obtaining data to estimate components of the weighted-average cost of capital, including the cost of debt capital, the cost of equity capital, and debt-to-equity ratio.
 - Comparing the weighted-average cost of capital selected by management with the range of independent estimates.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 12, 2020

We have served as the Partnership's auditor since 2019.

Report of Independent Registered Public Accounting Firm

To the Board of Directors of Tallgrass Energy GP, LLC, the general partner of Tallgrass Energy, LP, and the shareholders of Tallgrass Energy, LP

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Tallgrass Energy, LP and subsidiaries (the "Partnership") as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2019, of the Partnership and our report dated February 12, 2020, expressed an unqualified opinion on those consolidated financial statements, and included an explanatory paragraph regarding the Partnership's adoption of a new accounting standard related to leases in the year ended December 31, 2019.

Basis for Opinion

The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 12, 2020

Report of Independent Registered Public Accounting Firm

To the Board of Directors of Tallgrass Energy GP, LLC, the general partner of Tallgrass Energy, LP, and the shareholders of Tallgrass Energy, LP

Opinion on the Financial Statements

We have audited the consolidated balance sheet of Tallgrass Energy, LP and its subsidiaries (the "Partnership") as of December 31, 2018, and the related consolidated statements of income, equity and cash flows for each of the two years in the period ended December 31, 2018, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2018, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 2 and 12 to the consolidated financial statements, Rockies Express Pipeline LLC, an investment of the Partnership accounted for under the equity method, changed the manner in which it accounts for revenue in 2018.

Basis for Opinion

These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Denver, Colorado
February 8, 2019

We served as the Partnership's auditor from 2015 to 2019.

TALLGRASS ENERGY, LP
CONSOLIDATED BALANCE SHEETS

	December 31, 2019	December 31, 2018
	(in thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	\$ 9,394	\$ 9,596
Accounts receivable, net.....	324,281	236,097
Inventories	49,081	34,316
Prepayments and other current assets	12,490	11,816
Total Current Assets.....	395,246	291,825
Property, plant and equipment, net.....	2,774,518	2,802,429
Goodwill	441,361	421,983
Intangible assets, net	241,552	227,103
Unconsolidated investments	2,006,219	1,861,686
Deferred tax asset	318,202	273,531
Deferred charges and other assets	36,988	14,952
Total Assets.....	<u>\$ 6,214,086</u>	<u>\$ 5,893,509</u>
LIABILITIES AND EQUITY		
Current Liabilities:		
Accounts payable.....	\$ 246,347	\$ 201,512
Accrued taxes	24,921	20,734
Accrued interest.....	38,603	39,217
Accrued liabilities.....	50,988	23,287
Deferred revenue	127,932	111,095
Other current liabilities.....	38,273	42,910
Total Current Liabilities.....	527,064	438,755
Long-term debt, net	3,441,024	3,205,958
Other long-term liabilities and deferred credits	53,120	31,688
Total Long-term Liabilities.....	3,494,144	3,237,646
Commitments and Contingencies		
Equity:		
Class A Shareholders (179,583,765 and 156,311,986 shares outstanding at December 31, 2019 and 2018, respectively)	1,801,802	1,725,537
Class B Shareholders (102,136,875 and 123,887,893 shares outstanding at December 31, 2019 and 2018, respectively)	—	—
Total Partners' Equity.....	1,801,802	1,725,537
Noncontrolling interests ^(a)	391,076	491,571
Total Equity	2,192,878	2,217,108
Total Liabilities and Equity	<u>\$ 6,214,086</u>	<u>\$ 5,893,509</u>

^(a) See Note 11 – *Partnership Equity* for a complete description of our noncontrolling interests.

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

TALLGRASS ENERGY, LP
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2019	2018	2017
	(in thousands, except per unit amounts)		
Revenues:			
Crude oil transportation services	\$ 417,106	\$ 398,334	\$ 345,733
Natural gas transportation services	129,620	126,894	122,364
Sales of natural gas, NGLs, and crude oil	171,729	168,586	108,503
Processing and other revenues	150,093	99,445	79,298
Total Revenues	868,548	793,259	655,898
Operating Costs and Expenses:			
Cost of sales	94,816	114,815	91,213
Cost of transportation services	63,258	53,068	46,200
Operations and maintenance	88,474	72,460	62,069
Depreciation and amortization	128,825	110,862	90,800
General and administrative	104,373	70,656	65,536
Taxes, other than income taxes	35,669	31,810	28,832
Loss (gain) on disposal of assets	373	(11,043)	(599)
Total Operating Costs and Expenses	515,788	442,628	384,051
Operating Income	352,760	350,631	271,847
Other Income (Expense):			
Equity in earnings of unconsolidated investments	325,385	306,819	237,110
Interest expense, net	(161,407)	(133,319)	(89,348)
Other income (expense), net	2,410	(751)	12,834
Total Other Income (Expense)	166,388	172,749	160,596
Net income before tax	519,148	523,380	432,443
Income tax expense	(70,593)	(55,709)	(208,458)
Net income	448,555	467,671	223,985
Net income attributable to noncontrolling interests	(199,746)	(330,544)	(352,714)
Net income (loss) attributable to TGE	\$ 248,809	\$ 137,127	\$ (128,729)
Net income per Class A share:			
Basic net income (loss) per Class A share	\$ 1.42	\$ 1.27	\$ (2.22)
Diluted net income (loss) per Class A share	\$ 1.42	\$ 1.27	\$ (2.22)
Basic average number of Class A shares outstanding	174,816	107,586	58,076
Diluted average number of Class A shares outstanding	176,500	109,817	58,076

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

TALLGRASS ENERGY, LP
CONSOLIDATED STATEMENTS OF EQUITY

	Predecessor Equity	Partners' Capital				Noncontrolling Interests	Total Equity
		Class A Shares		Class B Shares			
		Shares	Amount	Shares	Amount		
				(in thousands)			
Balance at January 1, 2017	\$ 82,295	58,075	\$ 250,967	99,154	\$ —	\$ 1,596,152	\$ 1,929,414
Acquisition of Terminals and NatGas	(82,295)	—	(21,314)	—	—	(36,391)	(140,000)
Net income	—	—	(128,729)	—	—	352,714	223,985
Issuance of TEP units to public, net of offering costs	—	—	11,353	—	—	101,067	112,420
Dividends paid to Class A Shareholders.....	—	—	(73,321)	—	—	—	(73,321)
Noncash compensation expense	—	—	1,603	—	—	10,390	11,993
Issuance of TGE Class A shares under TGE LTIP plan	—	10	—	—	—	—	—
TEP LTIP units tendered by employees to satisfy tax withholding obligations.....	—	—	(1,317)	—	—	(11,616)	(12,933)
Partial exercise of call option	—	—	(12,052)	—	—	(72,890)	(84,942)
Repurchase of TEP common units from TD	—	—	(3,618)	—	—	(31,717)	(35,335)
Acquisition of additional 24.99% membership interest in Rockies Express.....	—	—	23,522	—	—	40,159	63,681
Acquisition of additional 40% membership interest in Deeprock Development	—	—	—	—	—	45,869	45,869
Acquisition of noncontrolling interests	—	—	669	—	—	(7,109)	(6,440)
Contributions from TD	—	—	850	—	—	1,451	2,301
Contributions from noncontrolling interests	—	—	—	—	—	1,589	1,589
Distributions to noncontrolling interests	—	—	—	—	—	(317,102)	(317,102)
Balance at December 31, 2017	\$ —	58,085	\$ 48,613	99,154	\$ —	\$ 1,672,566	\$ 1,721,179
Cumulative effect of ASC 606 implementation .	—	—	4,588	—	—	39,543	44,131
Net income	—	—	137,127	—	—	330,544	467,671
Dividends paid to Class A Shareholders.....	—	—	(206,431)	—	—	—	(206,431)
Noncash compensation expense	—	—	6,296	—	—	3,197	9,493
Acquisition of additional TEP common units from TD	—	—	(62,223)	10,758	—	(189,520)	(251,743)
Issuance of TE Units	—	—	—	—	—	644,782	644,782
Acquisition of additional 25.01% membership interest in Rockies Express.....	—	—	34,116	16,797	—	74,421	108,537
Acquisition of additional 2% membership interest in Pony Express	—	—	(5,268)	—	—	(44,732)	(50,000)
Consolidation of Deeprock North	—	—	—	—	—	31,843	31,843
Consolidation of BNN Colorado	—	—	—	—	—	10,138	10,138
Contributions from noncontrolling interests	—	—	—	—	—	1,787	1,787
Distributions to noncontrolling interests	—	—	—	—	—	(327,578)	(327,578)
Issuance of TEP units to public, net of offering costs	—	—	(98)	—	—	(279)	(377)
TEP LTIP units tendered by employees to satisfy tax withholding obligations.....	—	—	(190)	—	—	(1,531)	(1,721)
Issuance of Class A shares under LTIP plan, net of units tendered by employees to satisfy tax withholding obligations	—	19	(30)	—	—	—	(30)
Conversion of Class B to Class A shares.....	—	2,822	(8,717)	(2,822)	—	8,717	—
Deferred tax asset	—	—	15,427	—	—	—	15,427
Acquisition of additional TEP common units	—	—	(351,431)	—	—	(1,762,327)	(2,113,758)
Issuance of Class A shares	—	95,386	2,113,758	—	—	—	2,113,758
Balance at December 31, 2018	\$ —	156,312	\$1,725,537	123,887	\$ —	\$ 491,571	\$ 2,217,108

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

TALLGRASS ENERGY, LP
CONSOLIDATED STATEMENTS OF EQUITY

	Predecessor Equity	Partners' Capital				Noncontrolling Interests	Total Equity
		Class A Shares		Class B Shares			
		Shares	Amount	Shares	Amount		
		(in thousands)					
Net income	—	—	248,809	—	—	199,746	448,555
Dividends paid to Class A Shareholders.....	—	—	(371,605)	—	—	—	(371,605)
Noncash compensation expense	—	—	31,293	—	—	—	31,293
Deferred tax asset	—	—	115,370	—	—	—	115,370
Issuance of Class A shares under LTIP plan, net of units tendered by employees to satisfy tax withholding obligations	—	1,521	(16,216)	—	—	—	(16,216)
Conversion of Class B shares to Class A shares.	—	21,751	68,614	(21,751)	—	(68,614)	—
Contributions from noncontrolling interests	—	—	—	—	—	2,323	2,323
Distributions to noncontrolling interests	—	—	—	—	—	(237,350)	(237,350)
Acquisition of CES.....	—	—	—	—	—	3,400	3,400
Balance at December 31, 2019	\$ —	179,584	\$1,801,802	102,136	\$ —	\$ 391,076	\$ 2,192,878

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

TALLGRASS ENERGY, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2019	2018	2017
	(in thousands)		
Cash Flows from Operating Activities:			
Net income.....	\$ 448,555	\$ 467,671	\$ 223,985
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization.....	135,495	117,430	98,537
Equity in earnings of unconsolidated investments	(325,385)	(306,819)	(237,110)
Distributions from unconsolidated investments	326,018	306,934	237,192
Deferred income tax expense.....	69,865	55,709	208,458
Noncash compensation expense	31,293	10,665	8,898
Other noncash items, net.....	1,897	(13,047)	(9,400)
Changes in components of working capital:			
Accounts receivable and other.....	(78,617)	(102,105)	(57,927)
Accounts payable and accrued liabilities.....	88,490	112,474	84,731
Deferred revenue	16,873	17,547	27,283
Other current assets and liabilities.....	(21,558)	(3,079)	(10,542)
Other operating, net.....	(13,920)	9,145	(2,709)
Net Cash Provided by Operating Activities	679,006	672,525	571,396
Cash Flows from Investing Activities:			
Capital expenditures	(285,653)	(368,873)	(145,144)
Distributions from unconsolidated investments in excess of cumulative earnings.....	144,963	80,213	69,434
Contributions to unconsolidated investments.....	(115,545)	(473,946)	(45,948)
Sale of 50% membership interest in Cheyenne Connector	59,693	—	—
Acquisition of CES, net of cash acquired.....	(48,416)	—	—
Formation of Powder River Gateway joint venture	(37,000)	—	—
Acquisition of BNN North Dakota, net of cash acquired.....	—	(95,000)	—
Acquisition of NGL Water Solutions Bakken	—	(91,000)	—
Sale of Tallgrass Crude Gathering.....	—	50,046	—
Acquisition of membership interest in PLT.....	—	(30,704)	—
Acquisition of Pawnee Terminal	—	(30,600)	—
Acquisition of 38% membership interest in Deeprock North	—	(19,500)	—
Acquisition of Rockies Express membership interest	—	—	(400,000)
Acquisition of Terminals and NatGas	—	—	(140,000)
Acquisition of Douglas Gathering System	—	—	(128,526)
Acquisition of Deeprock Development, net of cash acquired.....	—	—	(57,202)
Acquisition of PRB Crude System	—	—	(36,030)
Other investing, net	(5,326)	(7,848)	(15,125)
Net Cash Used in Investing Activities.....	(287,284)	(987,212)	(898,541)
Cash Flows from Financing Activities:			
Dividends paid to Class A shareholders	(371,605)	(206,431)	(73,321)
Distributions to noncontrolling interests	(237,350)	(327,578)	(317,102)
Borrowings (repayments) under revolving credit facilities, net.....	232,000	417,000	(356,000)
TGE LTIP shares tendered by employees to satisfy tax withholding obligations	(16,216)	(30)	—

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

TALLGRASS ENERGY, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

Proceeds from issuance of long-term debt	—	500,000	1,103,750
Acquisition of Pony Express membership interest	—	(50,000)	—
Proceeds from public offering of TEP common units, net of offering costs	—	—	112,420
Partial exercise of call option	—	—	(72,381)
Repurchase of TEP common units from TD	—	—	(35,335)
Payments for deferred financing costs	—	—	(22,375)
Other financing, net	1,247	(11,271)	(12,377)
Net Cash (Used in) Provided by Financing Activities	(391,924)	321,690	327,279
Net Change in Cash and Cash Equivalents	(202)	7,003	134
Cash and Cash Equivalents, beginning of period	9,596	2,593	2,459
Cash and Cash Equivalents, end of period	<u>\$ 9,394</u>	<u>\$ 9,596</u>	<u>\$ 2,593</u>
Supplemental Disclosures:			
Cash payments for interest, net	\$ (155,945)	\$ (114,026)	\$ (72,698)
Schedule of Noncash Investing and Financing Activities:			
Contribution of assets to Powder River Gateway joint venture	\$ (111,707)	\$ —	\$ —
Accruals for property, plant and equipment	\$ 8,143	\$ 5,755	\$ 8,975
Right-of-use assets obtained in exchange for operating lease obligations	\$ 11,420	\$ —	\$ —
Issuance of 7.65% noncontrolling interest in BNN Eastern	\$ (3,400)	\$ —	\$ —
Acquisition of additional TEP common units ^{(a)(b)}	\$ —	\$ (2,365,501)	\$ —
Issuance of Class A shares ^(a)	\$ —	\$ 2,113,758	\$ —
Issuance of TE Units ^(b)	\$ —	\$ 644,782	\$ —
Acquisition of Rockies Express membership interest ^(b)	\$ —	\$ (393,039)	\$ —
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)	\$ —
TEP common units issued as partial consideration to acquire additional 9% membership interest in Deeprock Development	\$ —	\$ —	\$ 6,617

^(a) Represents the acquisition of additional TEP common units in exchange for Class A shares associated with the TEP Merger as discussed in Note 1 – *Description of Business*.

^(b) Represents the issuance of TE Units, as defined in Note 1 – *Description of Business*, associated with our acquisition of a 25.01% membership interest in Rockies Express and an additional 5,619,218 TEP common units as discussed in Note 3 – *Acquisitions and Dispositions*.

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

TALLGRASS ENERGY, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Description of Business

Tallgrass Energy, LP ("TGE") is a limited partnership that owns, operates, acquires and develops midstream energy assets in North America and has elected to be treated as a corporation for U.S. federal income tax purposes. "We," "us," "our" and similar terms refer to TGE together with its consolidated subsidiaries.

Our operations are conducted through, and our operating assets are owned by, our direct and indirect subsidiaries, including Tallgrass Equity, LLC ("Tallgrass Equity"), in which we directly own an approximate 63.75% membership interest as of December 31, 2019, and Tallgrass Energy Partners, LP ("TEP"), a wholly-owned subsidiary of Tallgrass Equity and its subsidiaries. We 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 an integrated natural gas storage facility;
- Crude Oil Transportation—the ownership and operation of FERC-regulated crude oil pipeline systems; 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 75% 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, Kansas, and the surrounding regions through (1) Tallgrass Pony Express Pipeline, LLC ("Pony Express"), which owns a FERC-regulated crude oil pipeline commencing in both Guernsey, Wyoming and Weld County, Colorado and terminating in Cushing, Oklahoma (the "Pony Express System") and (2) our 51% membership interest in Powder River Gateway, LLC ("Powder River Gateway"), which owns the Powder River Express Pipeline ("PRE Pipeline"), a 70-mile FERC-regulated crude oil pipeline that transports crude oil from the Powder River Basin to Guernsey, Wyoming, the Iron Horse Pipeline ("Iron Horse Pipeline"), a 80-mile FERC-regulated crude oil pipeline placed into service in May 2019 that transports crude oil from the Powder River Basin to Guernsey, Wyoming, and crude oil terminal facilities in Guernsey, Wyoming.

Gathering, Processing & Terminalling. We provide natural gas gathering and processing services for customers in Wyoming through (collectively, the "Midstream Facilities"): (1) a natural gas gathering system in the Powder River Basin (the "Douglas Gathering System"), (2) natural gas processing facilities in Casper and Douglas, and (3) a natural gas treating facility at West Frenchie Draw. 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, North Dakota, and Ohio 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.

Merger Agreement with Tallgrass Energy Partners, LP

TGE previously entered into a definitive Agreement and Plan of Merger, dated as of March 26, 2018 (the "TEP Merger Agreement"), with TEP, Tallgrass MLP GP, LLC, a Delaware limited liability company and the general partner of TEP ("TEP GP"), and Razor Merger Sub, LLC, a Delaware limited liability company. The merger transaction contemplated by the TEP Merger Agreement (the "TEP Merger") was completed effective June 30, 2018, and as a result, 47,693,097 TEP common units held by the public were converted into the right to receive Class A shares of TGE at an exchange ratio of 2.0 Class A shares for each outstanding TEP common unit, TEP's incentive distribution rights were cancelled, TEP's common units are no longer publicly traded, and 100% of TEP's equity interests are now owned by Tallgrass Equity and its subsidiaries. The TEP Merger

was accounted for as an acquisition of noncontrolling interest. Following consummation of the TEP Merger, TGE changed its name from "Tallgrass Energy GP, LP" to "Tallgrass Energy, LP" and began trading on the New York Stock Exchange under the ticker symbol "TGE" on July 2, 2018.

March 2019 Blackstone Acquisition

On March 11, 2019, pursuant to the terms of a previously announced definitive purchase agreement (the "Purchase Agreement"), dated January 30, 2019, entered into among acquisition vehicles controlled by affiliates of Blackstone Infrastructure Partners ("BIP" and, such acquisition vehicles controlled by BIP, collectively, the "March 2019 Acquirors"), affiliates of Kelso & Co., affiliates of The Energy & Minerals Group, Tallgrass KC, LLC, an entity owned by certain members of our management, and the other sellers named therein (collectively, the "Sellers"), the March 2019 Acquirors acquired from the Sellers (i) 100% of the membership interests in our general partner, (ii) 21,751,018 Class A shares representing limited partner interests ("Class A shares") in us, (iii) 100,655,121 units representing limited liability company interests ("TE Units") in Tallgrass Equity, and (iv) 100,655,121 Class B shares representing limited partner interests ("Class B shares") in us, in exchange for aggregate consideration of approximately \$3.2 billion in cash, which was paid to the Sellers (the "March 2019 Blackstone Acquisition").

As a result of the March 2019 Blackstone Acquisition, BIP effectively controls our business and affairs through the exercise of the rights of the sole member of our general partner. Additionally, the March 2019 Acquirors, Prairie Secondary Acquiror LP, a Delaware limited partnership ("Prairie Secondary Acquiror 1"), and Prairie Secondary Acquiror E LP, a Delaware limited partnership ("Prairie Secondary Acquiror 2" and, together with Prairie Secondary Acquiror 1 and the March 2019 Acquirors, the "Sponsor Entities"), each of which are also controlled by BIP, collectively held an approximate 44.1% economic interest in us as of December 31, 2019.

Take-Private Merger

On December 16, 2019, we and our general partner entered into a definitive Agreement and Plan of Merger (the "Take-Private Merger Agreement") with Prairie Private Acquiror LP, a Delaware limited partnership ("Buyer"), and Prairie Merger Sub LLC, a Delaware limited liability company and wholly owned subsidiary of Buyer ("Buyer Sub"). Buyer is an affiliate of the Sponsor Entities. Pursuant to the Take-Private Merger Agreement and subject to the satisfaction or waiver of certain conditions therein, Buyer will merge with and into TGE, with TGE surviving the merger and continuing to exist as a Delaware limited partnership (the "Take-Private Merger"). At the effective time of the Take-Private Merger (the "Effective Time"), each issued and outstanding Class A share other than the Class A shares owned by the Sponsor Entities and certain of their permitted transferees, will be converted into the right to receive \$22.45 per Class A share in cash without any interest thereon. Through the Take-Private Merger, the Sponsor Entities and the limited partners of Buyer immediately prior to the Effective Time will become the owners of all of the outstanding Class A shares and the Class A shares will cease to be publicly traded upon closing of the Take-Private Merger.

The Take-Private Merger Agreement is subject to the satisfaction of customary conditions, including approval of the merger by holders of a majority of the outstanding Class A and Class B shares of TGE, voting together as a single class, inclusive of the approximately 44.1% of the total Class A and Class B shares held by the Sponsors Entities as of December 31, 2019. As discussed in Note 11 – *Partnership Equity*, pursuant to the Take-Private Merger Agreement, TGE has agreed not to pay dividends during the pendency of the transactions contemplated by the Take-Private Merger Agreement.

2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying consolidated financial statements and related notes were prepared in conformity with accounting principles contained in the Financial Accounting Standards Board's Accounting Standards Codification ("ASC"), the single source of accounting principles generally accepted in the United States of America ("GAAP"). 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.

As further discussed in Note 3 – *Acquisitions and Dispositions*, we 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. The term "Predecessor Entities" refers to Terminals and NatGas prior to their acquisition by TEP on January 1, 2017. Predecessor Equity as presented in the consolidated financial statements represents the capital account activity of the Predecessor Entities prior to January 1, 2017. For additional information regarding these acquisitions, see Note 3 – *Acquisitions and Dispositions*.

The consolidated financial statements include the accounts of TGE and its subsidiaries and controlled affiliates. Intra-entity items have been eliminated in the presentation. Net income or loss from consolidated subsidiaries that are not wholly-owned by TGE is attributed to TGE and noncontrolling interests in accordance with the respective ownership interests. We have no elements of other comprehensive income for the periods presented.

A variable interest entity ("VIE") is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has a variable interest that could be significant to the VIE and the power to direct the activities that most significantly impact the entity's economic performance. We have presented separately in our consolidated balance sheets, to the extent material, the liabilities of our consolidated VIEs for which creditors do not have recourse to our general credit. Our consolidated VIEs did not have material assets that could only be used to settle specific obligations of the consolidated VIEs. Prior to June 29, 2018, both Tallgrass Equity and TEP were considered to be VIEs under the applicable authoritative guidance and included in our consolidated results. As a result of the TEP Merger, and changes in ownership and their respective partnership arrangements, Tallgrass Equity and TEP are no longer considered to be VIEs. We continue to consolidate our membership interests in Tallgrass Equity and TEP through the voting interest model.

Use of Estimates

Certain amounts included in or affecting these 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.

Cash and Cash Equivalents

We consider all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are carried at their estimated collectible amounts. We make periodic reviews and evaluations of the appropriateness of the allowance for doubtful accounts based on a historical analysis of uncollected amounts, and adjustments are recorded as necessary for changed circumstances and customer-specific information. When specific receivables are determined to be uncollectible, the reserve and receivable are relieved. Our allowance for doubtful accounts totaled \$0.7 million and \$7.7 million at December 31, 2019 and 2018, respectively.

Inventories

Inventories primarily consist of crude oil, materials and supplies, gas in underground storage, and natural gas liquids. A loss allowance is factored into the crude oil tariffs to offset losses in transit. As crude oil is transported, we earn oil for our services as pipeline loss allowance oil, or PLA, which we can then sell. As PLA oil is accumulated, it is recorded as inventory at the lower of historical cost and net realizable value using the average cost method. Materials and supplies are valued at weighted average cost and periodically reviewed for existence, physical deterioration, and obsolescence. Natural gas liquids and gas in underground storage, sometimes referred to as working gas, are recorded at the lower of historical cost and net realizable value using the average cost method. For additional information, see "*Gas in Underground Storage*" below.

Accounting for Regulatory Activities

Regulated activities are accounted for in accordance with the "Regulated Operations" Topic of the Codification. This Topic prescribes the circumstances in which the application of GAAP is affected by the economic effects of regulation. Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges and credits that will be recovered from or refunded to customers through the ratemaking process. We recorded regulatory assets of approximately \$2.6 million and \$3.2 million included in "Prepayments and other current assets" and "Deferred charges and other assets" in the consolidated balance sheets at December 31, 2019 and 2018, respectively. Regulatory assets at December 31, 2019 and December 31, 2018 were primarily attributable to costs associated with rate case filings and fuel tracker assets at our regulated natural gas pipelines. We recorded regulatory liabilities of approximately \$3.0 million and \$1.9 million included in "Other current liabilities" in the consolidated balance sheets at December 31, 2019 and 2018, respectively, related to fuel tracker

liabilities at our regulated natural gas pipelines. For further information regarding our rate case filings and fuel tracker balances, see Note 19 – *Regulatory Matters*.

Property, Plant and Equipment

Property, plant and equipment is stated at historical cost, which for constructed plants includes indirect costs such as payroll taxes, other employee benefits, allowance for funds used during construction for regulated assets and other costs directly related to the projects. Expenditures that increase capacities, improve efficiencies or extend useful lives are capitalized and depreciated over the remaining useful life of the asset or major asset component. We also capitalize certain costs related to the construction of assets, including internal labor costs, interest and engineering costs.

Routine maintenance, repairs and renewal costs are expensed as incurred. The cost of normal retirements of the regulated depreciable utility property, plant and equipment, plus the cost of removal less salvage value and any gain or loss recognized, is recorded in accumulated depreciation and/or the negative salvage liability discussed under "*Depreciation and Amortization*" below, as appropriate, with no effect on current period earnings. Gains or losses are recognized upon retirement of non-regulated or regulated property, plant and equipment constituting an operating unit or system, and land, when sold or abandoned and costs of removal or salvage are expensed when incurred.

Intangible Assets

We establish identifiable intangible assets when they meet either the separability criterion or the contractual-legal criterion. Contract-based intangible assets represent the value of rights that arise from contractual arrangements. Use rights such as drilling, water, air, timber cutting, and route authorities are an example of contract-based intangible assets. Intangible assets arose at Pony Express from the acquisition of rights associated with the ability and regulatory permissions to convert a section of TIGT's natural gas pipeline, which was subsequently purchased by Pony Express, to crude oil and includes the operational and financial benefits that accrue due to those rights and the ability to make that asset more valuable ("the Pony Express oil conversion use rights"). These intangible assets are amortized on a straight-line basis over a period of 35 years, the period of expected future benefit. During 2018, we recognized additional intangible assets at Plaquemines Liquids Terminal, LLC ("PLT"), a newly formed subsidiary as discussed in Note 3 – *Acquisitions and Dispositions*, from the acquisition of permits, designs, and other work-product related to the development and construction of a crude oil terminal facility in Louisiana. These intangible assets will be amortized on a straight-line basis over a period of 35 years, the period of expected future benefit. We recognized intangible assets associated with customer relationships as part of our acquisitions of NGL Water Solutions Bakken, LLC ("NGL Water Solutions Bakken") and BNN Eastern, LLC ("BNN Eastern") in 2018 and 2019, respectively, as discussed in Note 3 – *Acquisitions and Dispositions*. The customer relationships are amortized on a straight-line basis over a period of 8 years. Other intangible assets include customer contracts amortized on a straight-line basis over a period of 2 - 14 years, based on the remaining term of the contracts at the time of acquisition.

Impairment of Long-Lived Assets

We review our long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset or asset group may not be recoverable. An impairment loss results when the estimated undiscounted future net cash flows expected to result from the asset or asset group's use and its eventual disposition are less than its carrying amount. We assess our long-lived assets for impairment in accordance with the relevant Codification guidance. A long-lived asset or asset group is tested for impairment whenever events or changes in circumstances indicate its carrying amount may not be recoverable.

Examples of long-lived asset impairment indicators include:

- a significant decrease in the market value of a long-lived asset or asset group;
- a significant adverse change in the extent or manner in which a long-lived asset or asset group is being used or in its physical condition;
- a significant adverse change in legal factors or in the business climate could affect the value of long-lived asset or asset group, including an adverse action or assessment by a regulator which would exclude allowable costs from the rate-making process;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of the long-lived asset or asset group;
- a current period operating cash flow loss combined with a history of operating cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset or asset group; and
- a current expectation that, more likely than not, a long-lived asset or asset group will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.

When an impairment indicator is present, we first assess the recoverability of the long-lived assets by comparing the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset or asset group to its carrying amount. If the carrying amount is higher than the undiscounted future cash flows, the fair value of the asset or asset group is assessed using a discounted cash flow analysis and used to determine the amount of impairment, if any, to be recognized.

Gas in Underground Storage

Gas in underground storage represents the cost of base gas, which refers to the volumes necessary to maintain pressure and deliverability requirements in our storage facilities. We record base gas as a component of property, plant and equipment.

We maintain working gas in our underground storage facilities on behalf of certain third parties. We receive a fee for our storage services but do not reflect the value of third-party gas in the accompanying consolidated financial statements. We occasionally acquire volumes of working gas for our own account. These volumes of working gas are recorded as natural gas inventory at the lower of cost and net realizable value.

Depreciation and Amortization

For non-regulated assets, we have elected to use the straight-line method of depreciation. For our regulated assets, we have elected to compute depreciation using a composite method employed by applying a single depreciation rate to a group of assets with similar economic characteristics. This composite method of depreciation approximates a straight-line method of depreciation. The depreciation rates for our regulated natural gas pipeline assets include two components, one based on economic service life (capital recovery) and one based on net costs of removal (negative salvage). The accumulated liability related to negative salvage is classified as "Other long-term liabilities and deferred credits" in our consolidated balance sheets.

The rates of depreciation for the various classes of depreciable assets are as follows:

	Range of Depreciation Rates
Crude oil pipelines	2.8%
Natural gas pipelines	0.7% - 5.0%
Gathering & processing assets	2.2% - 5.0%
Water business assets.....	2.3% - 20.0%
Terminal assets	1.8% - 4.0%
Replacement Gas Facilities ⁽¹⁾	10.0%
General & other	2.9% - 25.0%

- ⁽¹⁾ Represents costs incurred by TIGT, and reimbursed by Pony Express, for the construction of certain gas facilities necessary to maintain existing natural gas service on the TIGT System after having sold approximately 433 miles of natural gas pipeline, and associated rights of way and certain other equipment, to Pony Express in 2013.

Gas Imbalances

Gas imbalances receivable and payable represent the difference between customer nominations and actual gas receipts from and gas deliveries to interconnecting pipelines under various operational balancing and imbalance agreements. Gas imbalances are either made up in-kind or settled in cash, subject to the terms and valuations of the various agreements. Imbalances are valued at applicable average market index prices. Gas imbalances receivable and payable are included in "Prepayments and other current assets" and "Other current liabilities" in the consolidated balance sheets.

Deferred Financing Costs

Costs incurred in connection with the issuance of long-term debt are deferred and amortized over the related financing period using the effective interest method. Deferred financing costs associated with long-term debt are presented as a reduction to the corresponding debt in our consolidated balance sheets. Deferred financing costs associated with our revolving credit facility are presented as noncurrent assets in our consolidated balance sheets. During the year ended December 31, 2018, we recognized a \$2.2 million loss on debt retirement, recorded as "Other income (expense), net" in the accompanying consolidated statements of income, associated with the write off of deferred financing costs associated with the Amendment to the TEP revolving credit facility and the termination of the Tallgrass Equity revolving credit facility as discussed further in Note 10 – *Long-term Debt*.

Goodwill

We evaluate goodwill for impairment on an annual basis and whenever events or changes in circumstances necessitate an evaluation for impairment. Examples of such facts and circumstances include changes in the magnitude of the excess of fair value over carrying amount in the last valuation or changes in the business environment. Our annual impairment testing date is August 31. We evaluate goodwill for impairment at the reporting unit level, which is the same as, or one level below, an operating segment as defined in the segment reporting guidance of the Codification, using either the qualitative assessment option or proceeding directly to the quantitative impairment test depending on facts and circumstances of the reporting unit. For the purpose of goodwill impairment testing, goodwill was allocated to our reporting units according to the benefit received by the reporting unit at the date of acquisition. If we, after performing the qualitative assessment, determine it is "more likely than not" that the fair value of a reporting unit is greater than its carrying amount, then goodwill is not considered impaired. When goodwill is evaluated for impairment using the quantitative impairment test, the carrying amount of the reporting unit is compared to its fair value. If the fair value exceeds the carrying amount, goodwill is not considered impaired. If the carrying amount exceeds the reporting unit's fair value, then the reporting unit should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. See Note 8 – *Goodwill and Other Intangible Assets* for additional information regarding impairment testing performed during 2019.

Investment in Unconsolidated Affiliates

We use the equity method to account for investments in 20% or greater owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and for investments in less than 20% owned affiliates where we have the ability to exercise significant influence.

We evaluate our investments in unconsolidated affiliates for impairment whenever events or changes in circumstances indicate that the carrying value of such investments may have experienced a decline in value. When there is evidence of loss in value, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. We assess the fair value of our investments in unconsolidated affiliates using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. The difference between the carrying amount of the unconsolidated affiliates and their estimated fair value is recognized as an impairment loss when the loss in value is deemed to be other-than-temporary. See Note 7 – *Investments in Unconsolidated Affiliates* for additional information regarding our investment in unconsolidated affiliates.

Revenue Recognition

We adopted Accounting Standards Update ("ASU") No. 2014-09, "Revenue from Contracts with Customers" on January 1, 2018, using the modified retrospective method. For periods subsequent to adoption, we account for revenue from contracts with customers in accordance with the five-step model outlined in ASC Topic 606, "*Revenue from Contracts with Customers*" ("ASC 606"). Under the five-step model, we identify the contract, identify the performance obligations, determine the transaction price, allocate the transaction price, and recognize revenue. Revenue is recognized when (or as) the performance obligations are satisfied. For additional information see Note 12 – *Revenue from Contracts with Customers*.

Commitments and Contingencies

We recognize liabilities for other commitments and contingencies when, after fully analyzing the available information, we determine it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. When a range of probable loss can be estimated, we accrue the most likely amount, or if no amount is more likely than another, we accrue the minimum of the range of probable loss.

Environmental Costs

We expense or capitalize, as appropriate, environmental expenditures that relate to current operations. We expense amounts that relate to an existing condition caused by past operations that do not contribute to current or future revenue generation. We do not discount environmental liabilities to a net present value, and record environmental liabilities when environmental assessments and/or remedial efforts are probable and costs can be reasonably estimated. Recording of these accruals coincides with the completion of a feasibility study or a commitment to a formal plan of action. Estimates of environmental liabilities are based on currently available facts and presently enacted laws and regulations taking into consideration the likely effects of other factors including our prior experience in remediating contaminated sites, other companies' clean-up experience and data released by government organizations. Our estimates are subject to revision in future periods based on actual cost or new information.

Fair Value

Fair value, as defined in the Codification, is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, or exit price. We apply the fair value measurement

guidance to financial assets and liabilities in determining the fair value of derivative assets and liabilities, and to nonfinancial assets and liabilities upon the acquisition of a business or in conjunction with the measurement of an impairment loss on an asset group or goodwill under the accounting guidance for the impairment of long-lived assets or goodwill.

The fair value measurement accounting guidance requires that we make assumptions that market participants would use in pricing an asset or liability based on the best information available. These factors include nonperformance risk (the risk that the obligation will not be fulfilled) and credit risk of the reporting entity (for liabilities) and of the counterparty (for assets). The fair value measurement guidance prohibits the inclusion of transaction costs and any adjustments for blockage factors in determining the instruments' fair value. The principal or most advantageous market should be considered from the perspective of the reporting entity.

Fair value, where available, is based on observable market prices. Where observable market prices or inputs are not available, different valuation models and techniques are applied. These models and techniques attempt to maximize the use of observable inputs and minimize the use of unobservable inputs. The process involves varying levels of management judgment, the degree of which is dependent on the price transparency of the instruments or market and the instruments' complexity.

To increase consistency and enhance disclosure of fair value, the Codification creates a fair value hierarchy to prioritize the inputs used to measure fair value into three categories. An asset or liability's level within the fair value hierarchy is based on the lowest level of input significant to the fair value measurement, where Level 1 is the highest and Level 3 is the lowest. The three levels are defined as follows:

- Level 1 Inputs-quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date;
- Level 2 Inputs-inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability; and
- Level 3 Inputs-unobservable inputs for the asset or liability. These unobservable inputs reflect the entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability, and are developed based on the best information available in the circumstances (which might include the reporting entity's own data).

Any transfers between levels within the fair value hierarchy are recognized at the end of the reporting period. For information regarding financial instruments measured at fair value on a recurring basis, see Note 9 – *Risk Management*. For information regarding the fair value of financial instruments not measured at fair value in the consolidated balance sheets, see Note 10 – *Long-term Debt*.

Risk Management Activities

Our operations expose us to a variety of risks including, but not limited to, changes in the prices of commodities that we buy or sell. We manage these exposures with either physical or financial transactions. We have established a comprehensive risk management policy and a risk management committee, or the Risk Management Committee, to monitor and manage market risks associated with commodity prices and counterparty credit. The Risk Management Committee is composed of senior executives who receive regular briefings on positions and exposures, credit exposures and overall risk management in the context of market activities. The Risk Management Committee is responsible for the overall management of credit risk and commodity price risk, including establishing and monitoring the adequacy of, and compliance with, exposure limits.

We record derivative contracts at their estimated fair values as of each reporting date and present profit and loss activity on a net basis in "Sales of natural gas, NGLs, and crude oil" in our consolidated statements of operations. For more information on our risk management activities, see Note 9 – *Risk Management*.

Equity-Based Compensation

Equity-based compensation grants are measured at their grant date fair value and related compensation cost is recognized over the vesting period of the grant. Compensation cost for awards with graded vesting provisions is recognized on a straight-line basis over the requisite service period of each separately vesting portion of the award. As discussed in Note 17 – *Equity-Based Compensation*, prior to February 2018 a portion of the expense recognized relating to equity-based compensation grants was charged to Tallgrass Development, LP ("TD").

Income Taxes

Although TGE is organized as a limited partnership, we have elected to be treated as a corporation for U.S. federal income tax purposes and are therefore subject to both U.S. federal and state income taxes. TGE's consolidated subsidiaries consist primarily of entities that are flow-through entities for income tax purposes. We also own certain C corporation subsidiaries which have been formed for the purpose of potential pipeline construction and other investment purposes. In addition, Tallgrass

Energy Finance Corp. is a wholly owned subsidiary of TEP that has no material assets and was formed for the sole purpose of being a co-issuer of TEP's senior notes as discussed in Note 10 – *Long-term Debt*. These C corporation subsidiaries have not commenced operations or generated any material income, and as a result no provision for federal or state income taxes for these entities has been recorded in our consolidated financial statements.

As discussed in Note 3 – *Acquisitions and Dispositions*, in April 2019, BNN Eastern, a newly formed indirect subsidiary of TGE, entered into a Stock Purchase Agreement to acquire all of the outstanding stock of CES Holding Company, Inc., which owns all of the issued and outstanding membership interests of K & H Partners LLC. CES Holding Company, Inc. is a C corporation for U.S. federal income tax purposes and is considered a taxable entity for such purposes.

Deferred income taxes are provided for temporary differences arising from differences between the consolidated financial statement and tax basis of assets and liabilities existing at each balance sheet date using enacted tax rates expected to be in effect when the related taxes are expected to be paid or recovered. A valuation allowance is established if it is more likely than not that a deferred tax asset will not be realized. In determining the appropriate valuation allowance, we consider projected realization of tax benefits based on expected levels of future taxable income, available tax planning strategies, and our overall deferred tax position.

Pursuant to the applicable guidance related to accounting for uncertainty in income taxes, we must recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based on the technical merits of the tax position and also the past administrative practices and precedents of the taxing authority. As of December 31, 2019, we had not recognized any material amounts in connection with uncertainty in income taxes.

Business Combinations

We recognize and measure the assets acquired and liabilities assumed in a business combination based on their estimated fair values at the acquisition date, with any remaining difference recorded as goodwill or gain from a bargain purchase. For material or complex acquisitions, management typically engages an independent valuation specialist to assist with the determination of fair value of the assets acquired, liabilities assumed, noncontrolling interest, if any, and goodwill, based on recognized business valuation methodologies. If the initial accounting for the business combination is incomplete by the end of the reporting period in which the acquisition occurs, an estimate will be recorded. Subsequent to the acquisition, and not later than one year from the acquisition date, we will record any material adjustments to the initial estimate based on new information obtained about facts and circumstances that existed as of the acquisition date. An income, market or cost valuation approach may be utilized to estimate the fair value of the assets acquired, liabilities assumed, and noncontrolling interest, if any, in a business combination. We typically use an income approach, such as the multi-period excess earnings method, to value intangible assets. The income approach requires management to estimate future cash flows: (i) discrete financial forecasts, which rely on management's estimates of gross margin and operating expenses; (ii) terminal growth rates; and (iii) appropriate discount rates. We typically use a cost approach to value property, plant and equipment. The cost approach is based on the replacement cost of a comparable asset at prices at the time of the acquisition reduced for depreciation of the asset. See Note 3 – *Acquisitions and Dispositions* for additional information regarding our business combinations.

Accounting Pronouncement Recently 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 within GAAP intended to increase transparency and comparability among organizations by recognizing right-of-use ("ROU") 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 has completed its evaluation and implemented the revised guidance using the modified retrospective method as of January 1, 2019. This approach allows us to (i) initially apply ASC 842 at the adoption date, January 1, 2019 and (ii) continue reporting comparative periods presented in the financial statements in the period of adoption under the previous guidance. Accordingly, we will not recast comparative periods in the consolidated financial statements. We have elected the package of practical expedients permitted under the transition guidance within the new standard, which among other things, allowed us to carry forward the historical lease classification. We have also elected the following practical expedients for all classes of leases: (a) the land easement practical expedient, allowing us to carry forward our accounting treatment for existing land easements as property, plant and equipment, (b) the practical expedient for short-term leases, allowing us to not recognize ROU assets or lease liabilities for leases with a term of 12 months or less, and (c) for agreements that contain both lease and non-lease components, combining these components together and accounting for them as a single lease.

Excluding ROU assets and lease liabilities relating to agreements between consolidated subsidiaries, adoption of the new standard resulted in the recognition of ROU assets of approximately \$2.3 million and current and non-current lease liabilities of approximately \$0.6 million and \$1.7 million, respectively, for operating leases as of January 1, 2019. Our accounting for finance leases remained substantially unchanged. The adoption of this guidance had no impact to our cash flows from operating, investing, or financing activities. For additional information see Note 13 – *Leases*.

Accounting Pronouncements Not Yet Adopted

ASU No. 2016-13, "Financial Instruments–Credit Losses (Topic 326)"

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments–Credit Losses (Topic 326). ASU 2016-13 amends current measurement techniques used to estimate credit losses for financial assets. The amendments in ASU 2016-13 are effective for financial statements issued for annual periods beginning after December 15, 2019, and interim periods within those annual periods. Early adoption is permitted. We are currently evaluating the impact of ASU 2016-13 but do not anticipate a material impact on our consolidated financial statements.

ASU No. 2019-12, "Income Taxes (Topic 740)"

In December 2019, the FASB issued ASU No. 2019-12, Income Taxes (Topic 740), which modifies ASC 740 to simplify the accounting for income taxes. The amendments in ASU 2019-12 are effective for financial statements issued for annual periods beginning after December 15, 2020, and interim periods within those annual periods. Early adoption is permitted. We are currently evaluating the impact of ASU 2019-12.

3. Acquisitions and Dispositions

Cheyenne Connector

In October 2019, a subsidiary of DCP Midstream, LP ("DCP") exercised its option to purchase a 50% membership interest in Cheyenne Connector, LLC ("Cheyenne Connector"), which is currently developing and constructing the Cheyenne Connector Pipeline as discussed in Note 19 – *Regulatory Matters*. Effective November 4, 2019, we entered into a limited liability company agreement with DCP under which DCP made initial contributions of \$59.7 million to Cheyenne Connector and entered into natural gas transportation agreements, in exchange for a 50% membership interest in Cheyenne Connector. Upon closing of the transaction, we derecognized the assets and liabilities of Cheyenne Connector, which primarily consisted of construction work in progress of \$134.4 million. No gain or loss was recognized on the deconsolidation as the carrying value was determined to approximate the fair value. We will account for our remaining 50% membership interest in Cheyenne Connector under the equity method of accounting and will continue to operate the Cheyenne Connector joint venture.

Acquisition of Central Environmental Services

In April 2019, BNN Eastern, a newly formed indirect subsidiary of TGE, entered into a Stock Purchase Agreement to acquire all of the outstanding stock of CES Holding Company, Inc., which owns all of the issued and outstanding membership interests of K & H Partners LLC, a company doing business as Central Environmental Services ("CES"). CES Holding Company, Inc. is a C corporation for U.S. federal income tax purposes and is considered a taxable entity for such purposes. CES owns and operates a salt water disposal facility located in the Utica and Marcellus area of Ohio. On May 1, 2019, the acquisition closed for cash consideration of approximately \$52 million paid at closing, and the issuance of a 7.65% membership interest in BNN Eastern to one of the sellers in the transaction. In addition, the transaction included a potential earn out payment to the sellers of approximately \$3 million based on the achievement of certain milestones during 2019, which was payable in cash or in additional membership interests in BNN Eastern. Because the milestones were not achieved, there will not be an earn out payment in connection with the transaction. 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:

	Preliminary	Adjustments	Final
	(in thousands)		
Accounts receivable	\$ 1,391	\$ —	\$ 1,391
Prepayments	67	—	67
Property, plant and equipment.....	6,900	4,400	11,300
Intangible asset.....	35,800	(2,900)	32,900 ⁽¹⁾
Accounts payable and accrued liabilities	(1,518)	—	(1,518) ⁽²⁾
Deferred tax liability	(8,557)	(189)	(8,746)
Net identifiable assets acquired	34,083	1,311	35,394
Goodwill.....	17,734	(1,311)	16,423
Net assets acquired (excluding cash)	<u>\$ 51,817</u>	<u>\$ —</u>	<u>\$ 51,817</u>

⁽¹⁾ The \$32.9 million intangible asset acquired represents customer relationships and is amortized on a straight-line basis over a period of 8 years.

⁽²⁾ Includes the estimated fair value of the liability for contingent consideration of \$0.7 million.

At June 30, 2019, the assets acquired and liabilities assumed in the acquisition were recorded at provisional amounts based on the preliminary purchase price allocation. During the three months ended September 30, 2019, the preliminary purchase price allocation was adjusted to reflect additional information obtained with respect to the property, plant and equipment acquired. The purchase price allocation was considered final as of September 30, 2019. The 7.65% equity interest in BNN Eastern held by noncontrolling interests was recorded at its acquisition date fair value of \$3.4 million. The fair value of the noncontrolling interests were determined using a discounted cash flow analysis and adjusted for lack of control. These fair value measurements are based on significant inputs, such as forecasted cash flows and discount rates, that are not observable in the market and thus represent fair value measurements categorized within Level 3 of the fair value hierarchy under ASC 820. The goodwill recognized of \$16.4 million is primarily attributed to synergies expected from combining the operations of TGE and CES. All the goodwill was assigned to our Gathering, Processing & Terminalling segment.

Actual revenue and net income attributable to TGE from CES of \$6.4 million and \$0.8 million, respectively, was recognized in the accompanying consolidated statements of income for the period from May 1, 2019 to December 31, 2019.

Consolidation of BNN Colorado

Effective December 1, 2018, we obtained control of BNN Colorado Water, LLC ("BNN Colorado") through an amendment to the voting rights in BNN Colorado's limited liability company agreement. Prior to the amendment, we accounted for our interest in BNN Colorado under the equity method of accounting. The consolidation was accounted for as a business combination under ASC 805. No gain or loss was recognized on the remeasurement of our 63% membership interest as of December 1, 2018, as the carrying value was determined to approximate the fair value. The 37% equity interest in BNN Colorado held by noncontrolling interests was recorded at its acquisition date fair value of \$10.1 million. These fair value measurements are based on significant inputs, such as forecasted cash flows and discount rates, that are not observable in the market and thus represent fair value measurements categorized within Level 3 of the fair value hierarchy under ASC 820.

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

Accounts receivable.....	\$ 4,053
Property, plant and equipment.....	18,535
Intangible asset	7,922 ⁽¹⁾
Accounts payable and accrued liabilities	(53)
Deferred revenue	(4,053)
Net identifiable assets acquired (excluding cash)	<u>\$ 26,404</u>

⁽¹⁾ The \$7.9 million intangible asset acquired represents a customer contract. This intangible asset is amortized on a straight-line basis over a period of approximately 3 years, the remaining term of the underlying contract at the time of acquisition.

At December 31, 2018, the assets acquired and liabilities assumed were recorded at provisional amounts based on the preliminary purchase price allocation. No adjustments were made to these provisional amounts and the allocation of assets acquired and liabilities assumed in the acquisition was considered final as of June 30, 2019. Actual revenue and net loss attributable to TGE from BNN Colorado of less than \$1.0 million was recognized in the accompanying consolidated statements of income for the period from December 1, 2018 to December 31, 2018.

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. BNN North Dakota owns a produced water gathering and disposal system in the Bakken basin. 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)	\$	<u>95,000</u>

- ⁽¹⁾ The \$46.8 million intangible asset acquired represents three major customer contracts. 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. No adjustments were made to these provisional amounts and the allocation of assets acquired and liabilities assumed in the acquisition was considered final as of June 30, 2018. Actual revenue and net income attributable to TGE from BNN North Dakota of \$18.8 million and \$4.7 million, respectively, was recognized in the accompanying consolidated statements of income for the period from January 12, 2018 to December 31, 2018.

Acquisition of NGL Water Solutions Bakken

In November 2018, we acquired 100% of the membership interests in NGL Water Solutions Bakken, a produced water disposal system in the Bakken basin, for cash consideration of approximately \$91.0 million. NGL Water Solutions Bakken was subsequently merged into BNN North Dakota. 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:

	Preliminary	Adjustments	Final
	(in thousands)		
Accounts receivable	\$ 3,599	\$ (3,599)	\$ —
Prepayments and other current assets	5	—	5
Property, plant and equipment	17,200	—	17,200
Intangible asset	54,000	—	54,000 ⁽¹⁾
Accounts payable and accrued liabilities	(949)	644	(305)
Net identifiable assets acquired	73,855	(2,955)	70,900
Goodwill	17,145	2,955	20,100
Net assets acquired	<u>\$ 91,000</u>	<u>\$ —</u>	<u>\$ 91,000</u>

- ⁽¹⁾ The \$54.0 million intangible asset acquired represents customer relationships and a customer contract. This intangible asset is amortized on a straight-line basis over a period of 3 - 8 years.

At December 31, 2018, the assets acquired and liabilities assumed in the acquisition were recorded at provisional amounts based on the preliminary purchase price allocation. During the six months ended June 30, 2019, the preliminary purchase price allocation was adjusted for certain immaterial items related to working capital adjustments and the allocation of assets acquired

and liabilities assumed in the acquisition was considered final as of June 30, 2019. The goodwill recognized of \$20.1 million is primarily attributed to synergies expected from combining the operations of TGE and NGL Water Solutions Bakken. All the goodwill was assigned to our Gathering, Processing & Terminalling segment. Actual revenue and net income attributable to TGE from NGL Water Solutions Bakken of \$1.4 million and \$0.5 million, respectively, was recognized in the accompanying consolidated statements of income for the period from November 30, 2018 to December 31, 2018.

Acquisition of Plaquemines Liquids Terminal, LLC

In November 2018, we entered into a joint venture agreement with Drexel Hamilton Infrastructure Fund I, L.P. ("DHIF") to jointly-own Plaquemines Liquids Terminal, LLC ("PLT"). PLT was formed with the intention of developing storage and terminalling facilities for both crude oil and refined products and export facilities capable of loading Suezmax and Very Large Crude Carriers vessels for international delivery on a site located on the Mississippi River in Plaquemines Parish, Louisiana. We made an initial cash contribution to PLT of \$30.7 million in exchange for a 100% preferred membership interest and a 80% common membership interest in PLT. DHIF contributed any and all assets and rights related to PLT in exchange for a 20% common membership interest and the right to receive certain special distributions. Our preferred and common membership interests are considered to be a controlling financial interest and PLT was consolidated accordingly. The transaction has been accounted for as an asset acquisition, with substantially all the fair value allocated to the assets and liabilities acquired based on their relative fair values. The intangible assets acquired, valued at approximately \$35 million, relate to permits, designs, and other work-product related to the development and construction of a crude oil terminal facility in Louisiana. The liabilities recognized relate to DHIF's right to receive special distributions totaling \$35 million, of which \$25 million is included in "Other current liabilities" and the remaining \$10 million is included in "Other long-term liabilities and deferred credits" in the consolidated balance sheets. The special distributions are contingent upon PLT reaching certain milestones in the development and construction of the project facilities. Also in November 2018, PLT entered into an agreement with the Plaquemines Port & Harbor Terminal District to lease the land site on which PLT expects to construct the facilities. The project is currently under development.

Acquisition of Pawnee Terminal

In January 2018, we entered into an agreement to acquire a 51% membership interest in a crude oil terminal located in Pawnee, Colorado ("Pawnee Terminal") from Zenith Energy Terminals Holdings, LLC for cash consideration of approximately \$30.6 million. The transaction closed on April 1, 2018. As the 51% membership interest does not represent a controlling interest in Pawnee, our investment in Pawnee Terminal is recorded under the equity method of accounting and reported as "Unconsolidated investments" on the consolidated balance sheets.

Acquisitions in Rockies Express and Additional TEP Common Units

In March 2017, TEP, TD, and Rockies Express Holdings, LLC, entered into a definitive Purchase and Sale Agreement, pursuant to which TEP acquired an additional 24.99% membership interest in Rockies Express from TD in exchange for cash consideration of \$400 million.

The 2017 transfer of the Rockies Express membership interest between TD and TEP is considered a transaction between entities under common control, but does not represent a change in reporting entity. As a result of the common control nature of the transaction, the acquisition resulted in the recognition of a noncash deemed contribution representing the excess carrying value of the 24.99% membership interest in Rockies Express acquired over the fair value of the consideration paid. For further discussion, see Note 11 – *Partnership Equity*.

In February 2018, TD merged into Tallgrass Development Holdings, LLC ("Tallgrass Development Holdings"), a wholly-owned subsidiary of Tallgrass Equity (the "TD Merger"). As a result of the TD Merger, Tallgrass Equity acquired a 25.01% membership interest in Rockies Express and an additional 5,619,218 TEP common units. As consideration for the acquisition, TGE and Tallgrass Equity issued 27,554,785 unregistered Class B shares and TE Units, valued at approximately \$644.8 million based on the closing price on February 6, 2018, to the limited partners of TD. Subsequent to the closing of the transaction, our aggregate membership interest in Rockies Express is 75%.

The 2018 transfer of the Rockies Express membership interest between TD and Tallgrass Equity is considered a transaction between entities under common control, but does not represent a change in reporting entity. As a result of the common control nature of the transaction, the acquisition resulted in the recognition of a noncash deemed contribution representing the excess carrying value of the 25.01% membership interest in Rockies Express acquired over the fair value of the consideration paid. For further discussion, see Note 11 – *Partnership Equity*. As the aggregate 75% membership interest does not represent a controlling interest in Rockies Express, TGE's investment in Rockies Express is recorded under the equity method of accounting and is reported as "Unconsolidated investments" on our consolidated balance sheets. For additional information, see Note 7 – *Investments in Unconsolidated Affiliates*.

The acquisition of an additional 5,619,218 TEP common units is considered an acquisition of noncontrolling interest and resulted in the recognition of a noncash deemed distribution representing the excess purchase price over the \$53.8 million

carrying value of the 5,619,218 TEP common units acquired as of February 7, 2018. For further discussion, see Note 11 – *Partnership Equity*.

Acquisition and Sale of Outrigger Powder River Operating, LLC

In August 2017, we acquired 100% of the membership interests of Outrigger Powder River Operating, LLC (subsequently renamed as Tallgrass Crude Gathering, LLC, "Tallgrass Crude Gathering"), which owns a crude oil gathering system in the Powder River Basin with approximately 34 miles of gathering lines as of the acquisition date and approximately 150,000 acres dedicated on a long-term fee-based contract (the "PRB Crude System"), for approximately \$36 million. 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.....	\$	117
Property, plant and equipment.....		29,306
Intangible asset		6,694 ⁽¹⁾
Accounts payable and accrued liabilities		(87)
Net identifiable assets acquired.....	\$	<u>36,030</u>

⁽¹⁾ The \$6.7 million intangible asset acquired represents a major customer contract. This intangible asset is amortized on a straight-line basis over a period of 8 years, the remaining term of the contract at the time of acquisition.

At September 30, 2017, the assets acquired and liabilities assumed in the acquisition were recorded at provisional amounts based on the preliminary purchase price allocation. No adjustments were made to these provisional amounts and the allocation of assets acquired and liabilities assumed in the acquisition was considered final as of December 31, 2017. Actual revenue and net loss attributable to TGE from Tallgrass Crude Gathering of less than \$1 million was recognized in the accompanying consolidated statements of income for the period from August 3, 2017 to December 31, 2017.

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, for approximately \$50.0 million. The sale of Tallgrass Crude Gathering closed on February 23, 2018. During the year ended December 31, 2018, we recognized a gain of \$9.4 million on the sale which is presented in the line item "Loss (gain) on disposal of assets" in the consolidated statements of income.

Joint Venture with Silver Creek

In February 2018, we entered into an agreement with Silver Creek to form Iron Horse Pipeline, LLC ("Iron Horse"), to construct and own the Iron Horse Pipeline. During the year ended December 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. As the 75% membership interest does not represent a controlling 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 consolidated balance sheets.

In August 2018, we entered into an agreement with Silver Creek to expand the Iron Horse joint venture through the contribution by us and Silver Creek of cash and additional Powder River Basin assets. These additional contributions closed in January 2019. We contributed our 75% membership interest in Iron Horse, \$37 million in cash, and various other assets, including terminal facilities currently under construction in Guernsey, Wyoming. Silver Creek contributed the PRE Pipeline and their 25% membership interest in Iron Horse. The expanded joint venture operates under the name Powder River Gateway, LLC ("Powder River Gateway"), and owns the Iron Horse Pipeline, the PRE Pipeline, a 70-mile crude oil pipeline that transports crude oil from the Powder River Basin to Guernsey, Wyoming, and crude oil terminal facilities in Guernsey, Wyoming. Effective January 1, 2019, we own a 51% membership interest in Powder River Gateway and continue to operate the joint venture, while Silver Creek owns a 49% membership interest. As Silver Creek retained certain participating rights with respect to Powder River Gateway, the 51% membership interest does not represent a controlling interest in Powder River Gateway. Accordingly, our investment in Powder River Gateway is accounted for under the equity method of accounting and reported as "Unconsolidated investments" on the consolidated balance sheets.

Acquisitions of Additional Interests in Deeprock Development, LLC

In July 2017, we acquired an additional 40% membership interest in Deeprock Development, LLC ("Deeprock Development") from Kinder Morgan Cushing, LLC for cash consideration of approximately \$57.2 million, net of cash acquired. We subsequently acquired an additional 9% membership interest in Deeprock Development from Deeprock Energy Resources LLC ("DER") on July 21, 2017, as discussed further below.

Upon closing of the acquisition of the 40% membership interest on July 20, 2017, we obtained a controlling financial interest in Deeprock Development and accordingly have accounted for the transaction as a step acquisition under ASC 805. On the acquisition date, we remeasured our previously held 20% equity interest in Deeprock Development to its fair value of \$22.9 million, recognized a gain of \$9.7 million in "Other income (expense), net" in the consolidated statements of income, and consolidated Deeprock Development in our consolidated financial statements. The 40% equity interest in Deeprock Development held by noncontrolling interests was recorded at its acquisition date fair value of \$45.9 million. The fair values of the previously held equity interest and the noncontrolling interest were determined using a discounted cash flow analysis and adjusted for lack of control. These fair value measurements are based on significant inputs, such as forecasted cash flows and discount rates, that are not observable in the market and thus represent fair value measurements categorized within Level 3 of the fair value hierarchy under ASC 820.

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

Accounts receivable	\$	968
Other current assets		598
Property, plant and equipment		70,148
Accounts payable		(712)
Deferred revenue		(6,546)
Net identifiable assets acquired		64,456
Goodwill		61,550
Net assets acquired (excluding cash)	\$	126,006

At September 30, 2017, the assets acquired and liabilities assumed in the acquisition were recorded at provisional amounts based on the preliminary purchase price allocation. No adjustments were made to these provisional amounts and the allocation of assets acquired and liabilities assumed in the acquisition was considered final as of December 31, 2017. The goodwill recognized of \$61.6 million is primarily attributed to synergies expected from combining our operations with the operations of Deeprock Development. All the goodwill was assigned to our Gathering, Processing & Terminalling segment. Actual revenue and net income attributable to TGE from Deeprock Development of \$10.5 million and \$0.9 million, respectively, was recognized in the accompanying consolidated statements of income for the period from July 20, 2017 to December 31, 2017.

In July 2017, subsequent to the acquisition of an additional 40% membership interest discussed above, we acquired an additional 9% membership interest in Deeprock Development from DER for total consideration valued at approximately \$13.1 million, consisting of approximately \$6.4 million in cash and the issuance of 128,790 TEP common units (valued at approximately \$6.7 million based on the July 20, 2017 closing price of TEP's common units), which was accounted for as an acquisition of noncontrolling interest. Subsequent to the closing of the transaction, our aggregate membership interest in Deeprock Development was 69%.

Acquisition of Deeprock North and Merger with Deeprock Development

In January 2018, we 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, and the members of Deeprock North and Deeprock Development received adjusted membership interests in the combined entity. As a result, we 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, we own an approximate 60% membership interest in the combined entity.

Acquisition of DCP Douglas, LLC

In June 2017, we acquired 100% of the membership interests in DCP Douglas, LLC (subsequently renamed as Tallgrass Midstream Gathering, LLC), which owns the Douglas Gathering System, a natural gas gathering system in the Powder River Basin with approximately 1,500 miles of gathering pipeline connected to the Douglas processing plant, for approximately \$128.5 million. The acquisition has been accounted for as an asset acquisition, with substantially all the fair value allocated to the long-lived assets acquired based on their relative fair values.

Acquisition of Tallgrass Terminals, LLC and Tallgrass NatGas Operator, LLC

In January 2017, we acquired 100% of the issued and outstanding membership interests in Terminals and 100% of the issued and outstanding membership interests in NatGas from TD for total cash consideration of \$140 million. These acquisitions are considered transactions between entities under common control, and a change in reporting entity. As a result of the common control nature of the transaction, the acquisitions resulted in the recognition of a noncash deemed distribution

representing the excess fair value of the consideration paid over the carrying value of Terminals and NatGas net assets acquired. For further discussion, see Note 11 – *Partnership Equity*.

Acquisition of Additional 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 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. As a result of the common control nature of the transaction, the acquisition resulted in the recognition of a noncash deemed distribution representing the excess fair value of the consideration paid over the carrying value of the 2% membership interest in Pony Express acquired. For further discussion, see Note 11 – *Partnership Equity*.

Pro Forma Financial Information

Unaudited pro forma revenue and net income attributable to TGE for the years ended December 31, 2019 and 2018 is presented below as if the acquisition of CES had been completed on January 1, 2018. Unaudited pro forma revenue and net income (loss) attributable to TGE for the years ended December 31, 2018 and 2017 is presented below as if the acquisitions of BNN North Dakota, NGL Water Solutions Bakken, and BNN Colorado had been completed on January 1, 2017. Unaudited pro forma revenue and net loss attributable to TGE for the year ended December 31, 2017 is presented below as if the acquisitions of Tallgrass Crude Gathering and Deeprock Development had been completed on January 1, 2016.

	Year Ended December 31,		
	2019	2018	2017
	(in thousands)		
Revenue.....	\$ 873,340	\$ 827,998	\$ 686,803
Net income (loss) attributable to TGE	\$ 249,644	\$ 141,988	\$ (129,155)

The pro forma financial information is not necessarily indicative of what the actual results of operations or financial position of TGE would have been if the transactions had in fact occurred on the date or for the period indicated, nor do they purport to project the results of operations or financial position of TGE for any future periods or as of any date. The pro forma financial information does not give effect to any cost savings, operating synergies, or revenue enhancements expected to result from the transactions or the costs to achieve these cost savings, operating synergies, and revenue enhancements. The pro forma revenue and net income (loss) includes adjustments to give effect to the estimated results of operations of CES, BNN North Dakota, NGL Water Solutions Bakken, BNN Colorado, Tallgrass Crude Gathering, and Deeprock Development for the periods presented. The pro forma net income (loss) also includes adjustments to eliminate the equity in earnings and gain on remeasurement of unconsolidated investment associated with our previously held 20% membership interest in Deeprock Development and to eliminate the equity in earnings associated with our 63% membership interest in BNN Colorado which was previously accounted for as an equity method investment.

4. Related Party Transactions

Totals of transactions with affiliated companies, excluding transactions disclosed elsewhere in these notes, are as follows:

	Year Ended December 31,		
	2019	2018	2017
	(in thousands)		
Processing and other revenues ⁽¹⁾	\$ 7,394	\$ 7,483	\$ 8,516
Cost of transportation services ⁽²⁾	\$ 940	\$ —	\$ 10,476
Charges to TGE: ⁽³⁾			
Property, plant and equipment, net	\$ —	\$ —	\$ 2,679
Other deferred charges	\$ —	\$ —	\$ 25
Operations and maintenance	\$ —	\$ —	\$ 29,881
General and administrative	\$ —	\$ —	\$ 41,676

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

- (2) Reflects rent expense for crude oil storage and terminalling services provided by Powder River Gateway and at the Deeprock Terminal prior to our consolidation of Deeprock Development during the third quarter of 2017, as discussed in Note 3 – *Acquisitions and Dispositions*.
- (3) Charges to TGE, inclusive of Tallgrass Equity and TEP, include indirectly charged wages and salaries, other compensation and benefits, and shared services for periods prior to January 1, 2018 pursuant to an Omnibus Agreement entered into by TEP and TEP GP with Tallgrass Energy Holdings, LLC and certain of its affiliates in connection with the closing of our initial public offering on May 17, 2013. Effective January 1, 2018, these costs are incurred by TGE directly.

Details of balances with affiliates included in "Accounts receivable, net" in the consolidated balance sheets are as follows:

	December 31, 2019	December 31, 2018
	(in thousands)	
Receivable from related parties:		
Powder River Gateway, LLC	\$ 12,071	\$ —
Rockies Express Pipeline LLC	3,998	3,447
Cheyenne Connector, LLC	575	—
Pawnee Terminal, LLC	125	115
Iron Horse Pipeline, LLC	—	186
Total receivable from related parties	<u>\$ 16,769</u>	<u>\$ 3,748</u>

Details of gas imbalances with affiliated shippers included in "Prepayments and other current assets" and "Other current liabilities" in the consolidated balance sheets are as follows:

	December 31, 2019	December 31, 2018
	(in thousands)	
Affiliate gas imbalance receivables	\$ 74	\$ 19
Affiliate gas imbalance payables	\$ 991	\$ 742

5. Inventory

The components of inventory at December 31, 2019 and 2018 consisted of the following:

	December 31, 2019	December 31, 2018
	(in thousands)	
Crude oil	\$ 46,164	\$ 23,205
Gas in underground storage	1,772	2,740
Materials and supplies	650	8,206
Natural gas liquids	495	165
Total inventory	<u>\$ 49,081</u>	<u>\$ 34,316</u>

6. Property, Plant and Equipment

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

	December 31, 2019	December 31, 2018
	(in thousands)	
Crude oil pipelines.....	\$ 1,375,036	\$ 1,313,976
Gathering, processing and terminalling assets	1,007,648	889,168
Natural gas pipelines	625,631	607,343
General and other ⁽¹⁾	175,537	180,299
Construction work in progress.....	72,842	191,994
Accumulated depreciation and amortization	(482,176)	(380,351)
Total property, plant and equipment, net ⁽²⁾	<u>\$ 2,774,518</u>	<u>\$ 2,802,429</u>

⁽¹⁾ Includes approximately \$30.7 million of land associated with the PLT capital lease as discussed in Note 13 – *Leases*.

⁽²⁾ Property, plant and equipment, net includes approximately \$464.8 million of assets at our regulated natural gas pipelines at December 31, 2019.

Depreciation expense was approximately \$109.4 million, \$102.7 million, and \$86.9 million for the years ended December 31, 2019, 2018, and 2017, respectively. Capitalized interest was approximately \$7.5 million, \$5.2 million, and \$1.1 million for the years ended December 31, 2019, 2018, and 2017, respectively.

7. Investments in Unconsolidated Affiliates

The following table summarizes our investments in unconsolidated affiliates:

	Percentage Ownership at December 31, 2019	Carrying Value as of December 31,	
		2019	2018
		(in thousands)	
Rockies Express Pipeline LLC	75%	\$ 1,714,857	\$ 1,794,987
Cheyenne Connector, LLC.....	50%	96,194	—
Powder River Gateway, LLC	51%	164,773	—
Pawnee Terminal, LLC	51%	30,395	31,232
Iron Horse Pipeline, LLC	Not applicable	—	35,467
Total investments in unconsolidated affiliates		<u>\$ 2,006,219</u>	<u>\$ 1,861,686</u>

Cheyenne Connector

As discussed in Note 3 – *Acquisitions and Dispositions*, DCP exercised its option to purchase a 50% membership interest in Cheyenne Connector. The transaction closed effective November 4, 2019 and we subsequently deconsolidated Cheyenne Connector's assets and liabilities and began accounting for our remaining 50% membership interest under the equity method of accounting.

Powder River Gateway and Iron Horse Pipeline

As discussed in Note 3 – *Acquisitions and Dispositions*, effective January 1, 2019 we contributed our membership interest in Iron Horse along with cash and other assets under construction to Powder River Gateway, a joint venture with Silver Creek, in exchange for a 51% membership interest in the joint venture.

BNN Colorado Water, LLC

As discussed in Note 3 – *Acquisitions and Dispositions*, we consolidated BNN Colorado effective December 1, 2018 and no longer account for our investment in BNN Colorado under the equity method of accounting.

Deerock Development

As discussed in Note 3 – *Acquisitions and Dispositions*, on July 20, 2017, we acquired an additional 40% membership interest in Deerock Development. As a result of the acquisition, we consolidated Deerock Development and effective July 20, 2017 we no longer account for our investment in Deerock Development under the equity method of accounting.

Rockies Express Basis Difference

Our investment in Rockies Express is recorded under the equity method of accounting and is reported as "Unconsolidated investments" on our consolidated balance sheets. On May 6, 2016, TEP acquired a 25% membership interest in Rockies Express. On that date, the difference between the fair value of our investment in Rockies Express of \$436.0 million and the book value of the underlying net assets resulted in a negative basis difference of approximately \$404.7 million. As discussed in Note 3 – *Acquisitions and Dispositions*, we acquired an additional 24.99% and 25.01% membership interest in Rockies Express from TD on March 31, 2017 and February 7, 2018, respectively. As of March 31, 2017, the negative basis difference carried over from TD from the transfer of the 24.99% Rockies Express membership interest was approximately \$386.8 million. As of February 7, 2018, the negative basis difference carried over from TD from the transfer of the 25.01% Rockies Express membership interest was approximately \$376.5 million. The transfer of the 24.99% Rockies Express membership interest between TD and TEP and the 25.01% Rockies Express membership interest between TD and Tallgrass Equity are considered transactions between entities under common control, but does not represent a change in reporting entity. As a result of the common control nature of the transactions, the 24.99% and 25.01% membership interests in Rockies Express were transferred to TEP and Tallgrass Equity, respectively, at TD's historical carrying amount, including the remaining unamortized basis difference driven by the difference between the fair value of the investments and the book value of the underlying assets and liabilities on November 13, 2012, the date of acquisition by TD.

The amount of the basis difference allocated to property, plant and equipment is accreted over 35 years, which equates to the 2.86% composite depreciation rate utilized by Rockies Express to depreciate the underlying property, plant and equipment. The amount allocated to long-term debt is amortized over the remaining life of the various debt facilities. At December 31, 2019, the basis difference for our membership interests in Rockies Express was allocated as follows:

	Basis Difference (in thousands)	Amortization Period
Long-term debt	\$ 42,845	2 - 25 years
Property, plant and equipment	(1,108,670)	35 years
Total basis difference	<u>\$ (1,065,825)</u>	

During the year ended December 31, 2019, we recognized equity in earnings associated with our 75% membership interest in Rockies Express of \$316.4 million, inclusive of the amortization of the negative basis difference, and received distributions from and made contributions to Rockies Express of \$458.7 million and \$62.2 million, respectively.

Rockies Express Senior Notes Offerings

On January 31, 2020, Rockies Express issued \$750 million in aggregate principal amount of senior notes. The issuance was composed of two tranches, \$400 million of 3.60% senior notes due 2025 and \$350 million of 4.80% senior notes due 2030. The proceeds of the issuance will be used to redeem the 5.625% senior notes due April 15, 2020 in March 2020.

On April 12, 2019, Rockies Express and U.S. Bank, National Association, as trustee, entered into an Indenture pursuant to which Rockies Express issued \$550 million in aggregate principal amount of 4.95% senior notes due 2029. Substantially all of the net proceeds received by Rockies Express from the senior notes offering were used to repay Rockies Express' \$525 million term loan facility.

Summarized Financial Information of Unconsolidated Affiliates

The following tables summarize the combined financial information of our investments in unconsolidated affiliates during the periods in which we held a membership interest for the periods indicated:

	December 31,	
	2019	2018
	(in thousands)	
Current assets	\$ 201,621	\$ 132,213
Noncurrent assets	\$ 6,430,144	\$ 6,031,066
Current liabilities	\$ 216,596	\$ 694,951
Noncurrent liabilities	\$ 2,211,448	\$ 1,502,906
Members' equity	\$ 4,203,721	\$ 3,965,422

	Year Ended December 31,		
	2019	2018	2017
	(in thousands)		
Revenue.....	\$ 931,025	\$ 930,771	\$ 860,115
Operating income	\$ 499,493	\$ 524,607	\$ 480,337
Net income	\$ 394,725	\$ 376,934	\$ 465,592

8. Goodwill and Other Intangible Assets

Reconciliation of Goodwill

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

	Natural Gas Transportation	Gathering, Processing & Terminalling	Total
	(in thousands)		
Balance at December 31, 2017	\$ 255,558	\$ 149,280	\$ 404,838
Goodwill acquired.....	—	17,145 ⁽¹⁾	17,145
Balance at December 31, 2018	255,558	166,425	421,983
Goodwill acquired.....	—	16,423 ⁽²⁾	16,423
Other adjustments	—	2,955 ⁽³⁾	2,955
Balance at December 31, 2019	<u>\$ 255,558</u>	<u>\$ 185,803</u>	<u>\$ 441,361</u>

⁽¹⁾ The \$17.1 million of goodwill was recorded in connection with the acquisition of NGL Water Solutions Bakken on November 30, 2018 as discussed further in Note 3 – *Acquisitions and Dispositions*.

⁽²⁾ The \$16.4 million of goodwill was recorded in connection with the acquisition of CES on May 1, 2019 as discussed further in Note 3 – *Acquisitions and Dispositions*.

⁽³⁾ The \$3.0 million goodwill adjustment was recorded in connection with a purchase price allocation adjustment related to the NGL Water Solutions Bakken acquisition as discussed further in Note 3 – *Acquisitions and Dispositions*.

Annual Goodwill Impairment Analysis

We elected to apply the qualitative assessment option for one of our five reporting units during our 2019 annual goodwill impairment testing. In conducting the qualitative assessment we considered relevant factors and circumstances that affect the fair value or carrying amount of the reporting entity. Such factors included changes in discount rates, projected cash flows, macroeconomic considerations, industry and market considerations, overall financial performance, prior quantitative results, and entity and reporting unit specific events. For this reporting unit, the results of the qualitative assessment indicated that it was more likely than not that the fair value of the reporting units exceeds its book value. As such, we did not perform a quantitative impairment analysis, and we concluded that no impairment was indicated as of August 31, 2019.

For the remaining four reporting units, we did not elect to apply the qualitative assessment option and instead we proceeded directly to the quantitative impairment test. We compared the fair value of the reporting units with their respective book values, including goodwill, by using an income approach based on a discounted cash flow analysis. The fair value of the reporting units was determined on a stand-alone basis from the perspective of a market participant and included a sensitivity analysis of the impact of changes in various assumptions. This approach required us to make long-term forecasts of future operating results and various other assumptions and estimates, the most significant of which are gross margin, operating expenses, general and administrative expenses, long-term growth rates, maintenance capital expenditures, and the weighted average cost of capital. The fair value of the reporting units was determined using significant unobservable inputs, considered Level 3 under the fair value hierarchy in the Codification. For these reporting units, the results of the quantitative impairment test indicated no impairment as the fair value of each reporting unit was greater than its respective book value. As a result, in accordance with the Codification guidance, we did not record a goodwill impairment during the nine months ended September 30, 2019. Unpredictable events or deteriorating market or operating conditions could result in a future change to the discounted cash flow models and cause impairments in the future. We continue to monitor potential impairment indicators to determine if a triggering event occurs and will perform additional goodwill impairment analyses as necessary.

Approximately \$79.2 million of goodwill is allocated to the Midstream Facilities reporting unit, which is a component of our Gathering, Processing & Terminalling segment. As a result of current market conditions, certain producers from which the Midstream Facilities reporting unit receives natural gas for processing have recently indicated that they currently expect to deliver lower volumes than previously anticipated. The results of the Midstream Facilities reporting unit's impairment testing as of August 31, 2019 indicate that the fair value of the reporting unit exceeds the carrying value by approximately 17%. As a result, no impairment charge was recorded. However our analysis includes assumptions related to the discount rate used to discount future cash flows, and reflects a gradual recovery of commodity prices and a corresponding increase in volumes over time. This reporting unit is sensitive to changes in the discount rate, as such increases in the discount rate, could result in a future impairment. Additionally, if our outlook is not realized, or our producers further decrease volumes, we may recognize an impairment in the future.

Other Intangible Assets

A summary of amortized intangible assets is as follows:

	December 31, 2019	December 31, 2018
	(in thousands)	
Pony Express oil conversion use rights	\$ 105,973	\$ 105,973
Customer contracts	60,348	60,348
Customer relationships	85,950	52,100
Plaquemines Liquids Terminal use rights and permits	35,000	35,000
Accumulated amortization	(45,719)	(26,318)
Intangible assets, net	<u>\$ 241,552</u>	<u>\$ 227,103</u>

Amortization of intangible assets was approximately \$19.4 million, \$8.1 million, and \$3.8 million for the years ended December 31, 2019, 2018, and 2017, respectively.

Estimated future amortization for the intangible assets is as follows (in thousands):

Year	Total
2020	\$ 20,527
2021	20,474
2022	17,324
2023	17,324
2024	17,324
Thereafter	113,579
Total ⁽¹⁾	<u>\$ 206,552</u>

⁽¹⁾ Excludes the \$35 million intangible asset at PLT, as discussed in Note 3 – *Acquisitions and Dispositions*, that will be amortized over 35 years beginning on the in-service date of the project facilities.

9. Risk Management

Stanchion engages in the business of trading energy related products and services, which exposes us to market variables and commodity price risk. We may enter into physical contracts or financial instruments with the objective of realizing a positive margin from the purchase and sale of these commodity-based instruments. We have a comprehensive risk management policy for Stanchion adopted by the board of directors of our general partner and a Risk Management Committee responsible for the overall management of credit risk and commodity risk at Stanchion, including establishing and monitoring adequacy of, and compliance with, exposure limits. We also occasionally 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 consolidated balance sheets:

	Balance Sheet Location	December 31, 2019	December 31, 2018
		(in thousands)	
Crude oil derivative contracts	Prepayments and other current assets	\$ 2,536	\$ 3,526
Crude oil derivative contracts	Other current liabilities	\$ 60	\$ 1,642

As of December 31, 2019, the amounts shown represent the fair value of crude oil derivative contracts for the forward purchase of 2,394,002 and the forward sale of 5,913,554 barrels of crude oil consisting of fixed price and floating price contracts, which will settle throughout 2020. As of December 31, 2018, the amounts shown represent the fair value of crude oil derivative contracts for the forward purchase of 2,105,146 and the forward sale of 1,274,500 barrels of crude oil, consisting of fixed price and floating price contracts, which settled throughout 2019.

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 years ended December 31, 2019, 2018 and 2017:

		Amount of gain recognized in income on derivatives		
	Location of gain recognized in income on derivatives	Year Ended December 31,		
		2019	2018	2017
		(in thousands)		
Crude oil derivative contracts	Sales of natural gas, NGLs, and crude oil	\$ 55,562	\$ 29,510	\$ 39
Natural gas derivative contracts	Sales of natural gas, NGLs, and crude oil	\$ —	\$ —	\$ 75
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 TEP an 18 month call option at an exercise price of \$42.50 per TEP common unit covering the 6,518,000 TEP common units issued to TD as a portion of the consideration. On February 1, 2017, TEP exercised the remainder of the call option covering 1,703,094 common units for a cash payment of \$72.4 million. As a result of the exercise, we derecognized the derivative asset balance, recognizing approximately \$12.6 million through equity for the year ended December 31, 2017. 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.

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 December 31, 2019 was:

	Asset Position	
	(in thousands)	
Gross.....	\$	2,536
Netting agreement impact.....		—
Cash collateral held		—
Net exposure.....	\$	2,536

As of December 31, 2019, we had \$2.6 million of cash in margin accounts in support of our commodity derivative contracts. As of December 31, 2018, we did not have any cash in margin accounts 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 following table summarizes the fair value measurements of our derivative contracts as of December 31, 2019 and 2018, based on the fair value hierarchy:

		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)	
Total		(in thousands)			
As of December 31, 2019:					
Crude oil derivative contracts.....	\$ 2,536	\$ —	\$ 2,536	\$ —	
As of December 31, 2018:					
Crude oil derivative contracts.....	\$ 3,526	\$ —	\$ 3,526	\$ —	

		Liability 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)	
Total		(in thousands)			
As of December 31, 2019:					
Crude oil derivative contracts	\$ 60	\$ —	\$ 60	\$ —	
As of December 31, 2018:					
Crude oil derivative contracts	\$ 1,642	\$ —	\$ 1,642	\$ —	

10. Long-term Debt

Our long-term debt is held at TEP and consisted of the following at December 31, 2019 and 2018:

	December 31, 2019	December 31, 2018
	(in thousands)	
Revolving credit facility	\$ 1,456,000	\$ 1,224,000
4.75% senior notes due October 1, 2023	500,000	500,000
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⁾	(18,004)	(21,421)
Plus: Unamortized premium on 2028 Notes	3,028	3,379
Total long-term debt, net	<u>\$ 3,441,024</u>	<u>\$ 3,205,958</u>

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

Senior Unsecured Notes

On February 27, 2019, TEP and Tallgrass Energy Finance Corp. (together, the "Issuers"), together with the TEP subsidiary guarantors party thereto (the "Guarantors") and U.S. Bank National Association, as trustee (the "Trustee"), entered into supplemental indentures (the "Supplemental Indentures") to amend certain provisions of each of (i) the Indenture governing the 4.75% senior notes due 2023 (the "2023 Notes"), dated as of September 26, 2018, among the Issuers, the Guarantors and Trustee, (ii) the Indenture governing the 5.50% senior notes due 2024 (the "2024 Notes"), dated as of September 1, 2016, among the Issuers, the Guarantors and the Trustee, and (iii) the Indenture governing the 5.50% senior notes due 2028 (the "2028 Notes"), dated as of September 15, 2017, among the Issuers, the Guarantors and the Trustee (collectively, the "Indentures"). The Supplemental Indentures (a) amended the defined term "Change of Control" in each Indenture to provide that the March 2019 Blackstone Acquisition did not constitute a Change of Control under such Indenture, (b) changed the definition of "Qualifying Owners" in the applicable Indenture to provide that Blackstone Infrastructure Partners L.P., Vencap Holdings (1992) Pte. Ltd. and their respective affiliates, funds, holding companies and investment vehicles, among others, are Qualifying Owners under such Indenture, and (c) added to, amended, supplemented or changed certain other defined terms contained in each Indenture related to the foregoing.

The Issuers have previously issued \$500 million in aggregate principal amount of 4.75% senior notes due 2023 on September 26, 2018. The Indenture governing the 2023 Notes 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.

In addition, the Issuers have previously issued \$500 million in aggregate principal amount of 5.50% senior notes due 2028 on September 15, 2017 and an additional \$250 million in aggregate principal amount of the 2028 Notes on December 11, 2017. The 2028 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 Indenture governing the 2028 Notes 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.

In addition, the Issuers have also previously issued \$400 million in aggregate principal amount of 5.50% senior notes due 2024 on September 1, 2016 and an additional \$350 million in aggregate principal amount of the 2024 Notes on May 16, 2017. The 2024 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 Indenture governing the 2024 Notes 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.

The 2023 Notes, 2024 Notes, and 2028 Notes are together referred to as the "Senior Notes." As of December 31, 2019, TEP was in compliance with the covenants required under the Indentures.

Revolving Credit Facility

The following table sets forth the available borrowing capacity under the revolving credit facility as of December 31, 2019 and 2018:

	December 31, 2019	December 31, 2018
	(in thousands)	
Total capacity under the revolving credit facility	\$ 2,250,000	\$ 2,250,000
Less: Outstanding borrowings under the revolving credit facility	(1,456,000)	(1,224,000)
Less: Letters of credit issued under the revolving credit facility	(94)	(94)
Available capacity under the revolving credit facility	<u>\$ 793,906</u>	<u>\$ 1,025,906</u>

On February 22, 2019, TEP and certain of its subsidiaries entered into a Consent and Amendment No. 2 to the Second Amended and Restated Credit Agreement (the "Consent and Amendment") with Wells Fargo Bank, National Association, as administrative agent, and the required lenders party thereto. The Consent and Amendment modified that certain Second Amended and Restated Credit Agreement dated as of June 2, 2017, as previously amended by that certain Amendment No. 1 to Second Amended and Restated Credit Agreement dated as of July 26, 2018 (as amended, the "Credit Agreement"). The Credit Agreement governs our revolving credit facility, which matures on June 2, 2022.

In the Consent and Amendment, the required lenders under the Credit Agreement (i) consented to the March 2019 Blackstone Acquisition pursuant to the terms and conditions of the Purchase Agreement, (ii) agreed that no Default (as defined in the Credit Agreement) under the Credit Agreement, if any, that may have resulted from a Change in Control (as defined in the Credit Agreement) caused by the consummation of the March 2019 Blackstone Acquisition pursuant to the terms and conditions set forth in the Purchase Agreement will be deemed to have occurred, and (iii) agreed to modify the definition of "Permitted Holders" in Section 1.01 of the Credit Agreement (which is used in the definition of Change in Control) to reflect the change in ownership as a result of the March 2019 Blackstone Acquisition.

On July 26, 2018, TEP and certain of its subsidiaries entered into Amendment No. 1 (the "Amendment") to its existing revolving credit facility with Wells Fargo Bank, National Association, as administrative agent and collateral agent, and a syndicate of lenders. The Amendment modified certain provisions of the Credit Agreement to, among other things, (i) increase the available amount of the revolving credit facility to \$2.25 billion, (ii) reduce certain applicable margins in the pricing grids used to determine the interest rate and revolving credit commitment fees, (iii) modify the use of proceeds to allow TEP to pay off the Tallgrass Equity revolving credit facility, and (iv) increase the maximum total leverage ratio to 5.50 to 1.00.

The revolving credit facility contains various covenants and restrictive provisions that, among other things, limit or restrict TEP's ability (as well as the ability of its 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 its 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, TEP is required to maintain a consolidated leverage ratio of not more than 5.50 to 1.00, 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 December 31, 2019, TEP was in compliance with the covenants required under its revolving credit facility.

The unused portion of the revolving credit facility is subject to a commitment fee, which ranges from 0.250% to 0.375%, based on TEP's total leverage ratio. As of December 31, 2019, the weighted average interest rate on outstanding borrowings under the revolving credit facility was 3.13%. During the year ended December 31, 2019, the weighted average effective interest rate under the revolving credit facility, including the interest on outstanding borrowings under the revolving credit facility, commitment fees, and amortization of deferred financing costs, was 4.18%.

Tallgrass Equity Revolving Credit Facility

On July 26, 2018, Tallgrass Equity repaid all outstanding borrowings and terminated its revolving credit facility.

Fair Value

The following table sets forth the carrying amount and fair value of long-term debt, which is not measured at fair value in the consolidated balance sheets as of December 31, 2019 and 2018, but for which fair value is disclosed:

	Fair Value				Total	Carrying Amount	
	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 December 31, 2019:							
Revolving credit facility	\$	—	\$ 1,456,000	\$	—	\$ 1,456,000	\$ 1,456,000
2023 Notes.....	\$	—	\$ 500,065	\$	—	\$ 500,065	\$ 495,750
2024 Notes.....	\$	—	\$ 754,043	\$	—	\$ 754,043	\$ 742,723
2028 Notes.....	\$	—	\$ 735,375	\$	—	\$ 735,375	\$ 746,551
As of December 31, 2018:							
Revolving credit facility	\$	—	\$ 1,224,000	\$	—	\$ 1,224,000	\$ 1,224,000
2023 Notes.....	\$	—	\$ 485,285	\$	—	\$ 485,285	\$ 494,603
2024 Notes.....	\$	—	\$ 737,745	\$	—	\$ 737,745	\$ 741,196
2028 Notes.....	\$	—	\$ 726,503	\$	—	\$ 726,503	\$ 746,159

The long-term debt borrowed under the revolving credit facility is carried at amortized cost. As of December 31, 2019 and 2018, the fair value of borrowings under the revolving credit facility approximates the carrying amount of the borrowings using a discounted cash flow analysis. The Senior Notes are carried at amortized cost, net of deferred financing costs. The estimated fair value of the Senior 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 December 31, 2019.

11. Partnership Equity

TGE Dividends to Holders of Class A Shares

The following table details the dividends for the periods indicated:

Three Months Ended	Date Paid	Dividends to Class A Shareholders	Dividends per Class A Share
(in thousands, except per share amounts)			
December 31, 2019	Not applicable.....	\$ —	\$ —
September 30, 2019	November 14, 2019	98,559	0.5500
June 30, 2019	August 14, 2019	96,767	0.5400
March 31, 2019	May 15, 2019	94,975	0.5300
December 31, 2018	February 14, 2019	81,304	0.5200
September 30, 2018	November 14, 2018	79,717	0.5100
June 30, 2018	August 14, 2018	77,052	0.4975
March 31, 2018	May 15, 2018	28,316	0.4875
December 31, 2017	February 14, 2018	21,346	0.3675
September 30, 2017	November 14, 2017	20,617	0.3550
June 30, 2017	August 14, 2017	19,891	0.3425
March 31, 2017	May 15, 2017	16,697	0.2875

As a result of the Take-Private Merger Agreement discussed in Note 1 – *Description of Business*, TGE has agreed to not pay dividends with respect to its Class A shares and to not permit Tallgrass Equity to pay any distributions on its TE Units during the pendency of the transactions contemplated by the Take-Private Merger Agreement, in each case, without the prior written consent of Buyer. Therefore, no dividends have been declared for the three months ended December 31, 2019. However, in the event the Take-Private Merger Agreement is terminated, the board of directors of our general partner will

promptly fix a record date and declare and pay a dividend to the holders of Class A shares in an amount equal to the amount of dividends that otherwise would have been paid during the pendency of the transactions contemplated by the Take-Private Merger Agreement, all in accordance with our partnership agreement.

Subsidiary Distributions

TEP Distributions. The following table shows the distributions for the periods indicated:

Three Months Ended	Date Paid	Distributions				Distribution per Limited Partner Common Unit
		Limited Partner Common Units	General Partner		Total	
			Incentive Distribution Rights	General Partner Units		
(in thousands, except per unit amounts)						
March 31, 2018	May 15, 2018	\$ 71,370	\$ 39,816	\$ 1,267	\$ 12,453	\$ 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

As a result of the TEP Merger, Tallgrass Equity and its wholly-owned subsidiary, Tallgrass Equity Investments, LLC, will receive all distributions paid by TEP for the second quarter of 2018 and subsequent periods.

Exchange Rights

Our current Class B shareholders (collectively, the "Exchange Right Holders") own an equal number of TE Units. The Exchange Right Holders, and any permitted transferees of their TE Units, each have the right to exchange all or a portion of their TE Units for Class A shares at an exchange ratio of one Class A share for each TE Unit exchanged, which we refer to as the Exchange Right. The Exchange Right may be exercised only if, simultaneously therewith, an equal number of our Class B shares are transferred by the exercising party to us. Upon such exchange, we will cancel the Class B shares received from the exercising party. During the year ended December 31, 2019, 21,751,018 Class A shares were issued and an equal number of Class B shares were cancelled as a result of the exercise of the Exchange Right. During the year ended December 31, 2018, 2,821,332 Class A shares were issued and an equal number of Class B shares were cancelled as a result of the exercise of the Exchange Right.

Following the March 2019 Blackstone Acquisition that closed on March 11, 2019 discussed in Note 1 – *Description of Business*, the Exchange Rights Holders consist of certain of the Sponsor Entities and certain current and former members of our management.

Equity Distribution Agreements

Neither TGE nor TEP currently have equity distribution agreements in place. TEP was previously a party to equity distribution agreements pursuant to which it sold from time to time through a group of managers, as its sales agents, TEP common units representing limited partner interests. Following the TEP Merger, these agreements were terminated effective July 2, 2018.

During the year ended December 31, 2018, TEP did not issue any common units under its equity distribution agreements. During the year ended December 31, 2017, TEP issued and sold 2,341,061 common units with a weighted average sales price of \$48.82 per unit under its equity distribution agreements for net cash proceeds of approximately \$112.4 million (net of approximately \$1.9 million in commissions and professional service expenses). TEP used the net cash proceeds for general partnership purposes.

Repurchase of TEP Common Units Owned by TD

Following an offer received from TD with respect to TEP common units owned by TD not subject to the call option, TEP repurchased 736,262 TEP 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 TEP's general partner. These common units were deemed canceled upon TEP's purchase and as of such transaction date were no longer issued and outstanding.

Noncontrolling Interests

As of December 31, 2019, noncontrolling interests in our subsidiaries consisted of a 36.25% interest in Tallgrass Equity held by the Exchange Right Holders, as well as noncontrolling interests in certain subsidiaries held by unaffiliated third parties,

including an approximate 40% membership interest in Deeprock Development, an approximate 25% membership interest in BNN West Texas, LLC ("BNN West Texas"), a 37% membership interest in BNN Colorado, a 20% common membership interest in PLT, and an approximate 8% membership interest in BNN Eastern. During the year ended December 31, 2019, we recognized contributions from and distributions to noncontrolling interests of \$2.3 million and \$237.4 million, respectively. Distributions to noncontrolling interests consisted of Tallgrass Equity distributions to the Exchange Right Holders of \$229.9 million and distributions to Deeprock Development, BNN West Texas, BNN Colorado, and BNN Eastern noncontrolling interests of \$7.5 million in the aggregate.

During the year ended December 31, 2018, we recognized contributions from and made distributions to noncontrolling interests of \$1.8 million and \$327.6 million, respectively. Distributions to noncontrolling interests consisted of Tallgrass Equity distributions to the Exchange Right Holders of \$223.7 million, distributions to TEP unitholders of \$97.7 million, and distributions to Pony Express and Deeprock Development noncontrolling interests of \$6.2 million in the aggregate.

During the year ended December 31, 2017, we recognized contributions from and made distributions to noncontrolling interests of \$1.6 million and \$317.1 million, respectively. Distributions to noncontrolling interests consisted of distributions to TEP unitholders of \$185.7 million, Tallgrass Equity distributions to the Exchange Right Holders of \$125.2 million, and distributions to Pony Express and Deeprock Development noncontrolling interests of \$6.2 million in the aggregate.

Other Contributions and Distributions

During the year ended December 31, 2018, TGE recognized the following other contributions and distributions:

- TGE was deemed to have made a noncash capital distribution of \$198.0 million, which represents the excess purchase price over the \$53.8 million carrying value of the 5,619,218 TEP common units acquired as of February 7, 2018;
- TGE was deemed to have received a noncash capital contribution of \$108.5 million, which represents the excess carrying value of the 25.01% membership interest in Rockies Express acquired as of February 7, 2018 over the fair value of the consideration paid; and
- TEP was deemed to have made a noncash capital distribution of \$16.2 million, which represents the excess purchase price over the \$33.8 million carrying value of the additional 2% membership interest in Pony Express acquired as of February 1, 2018.

During the year ended December 31, 2017, TGE recognized the following other contributions and distributions:

- TEP was deemed to have made a noncash capital distribution of \$57.7 million, which represents the excess purchase price over the \$82.3 million carrying value of the Terminals and NatGas net assets acquired January 1, 2017;
- TEP was deemed to have received a noncash capital contribution of \$63.7 million, 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; and
- 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 20 – *Legal and Environmental Matters*.

12. Revenue from Contracts with Customers

Disaggregated Revenue

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

Year Ended December 31, 2019					
	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	\$ —	\$ 395,297	\$ —	\$ —	\$ 395,297
Natural gas transportation - firm service	125,170	—	—	(2,161)	123,009
Water business services	—	—	102,287	—	102,287
Natural gas gathering & processing fees	—	—	25,679	—	25,679
All other ⁽¹⁾	14,040	80,520	20,977	(74,377)	41,160
Total service revenue	139,210	475,817	148,943	(76,538)	687,432
Natural gas liquids sales	—	—	68,238	—	68,238
Natural gas sales	542	—	35,935	—	36,477
Crude oil sales	—	10,830	622	—	11,452
Total commodity sales revenue	542	10,830	104,795	—	116,167
Total revenue from contracts with customers	139,752	486,647	253,738	(76,538)	803,599
Other revenue ⁽²⁾	—	—	82,157	(17,208)	64,949
Total revenue ⁽³⁾	\$ 139,752	\$ 486,647	\$ 335,895	\$ (93,746)	\$ 868,548

Year Ended December 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	\$ —	\$ 392,276	\$ —	\$ —	\$ 392,276
Natural gas transportation - firm service	128,041	—	—	(4,585)	123,456
Water business services	—	—	52,333	—	52,333
Natural gas gathering & processing fees	—	—	24,109	—	24,109
All other ⁽¹⁾	11,223	45,888	18,444	(53,950)	21,605
Total service revenue	139,264	438,164	94,886	(58,535)	613,779
Natural gas liquids sales	—	—	101,382	—	101,382
Natural gas sales	1,195	—	29,558	—	30,753
Crude oil sales	—	6,290	652	—	6,942
Total commodity sales revenue	1,195	6,290	131,592	—	139,077
Total revenue from contracts with customers	140,459	444,454	226,478	(58,535)	752,856
Other revenue ⁽²⁾	—	—	53,187	(12,784)	40,403
Total revenue ⁽³⁾	\$ 140,459	\$ 444,454	\$ 279,665	\$ (71,319)	\$ 793,259

- (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 revenue recognized at unconsolidated investments of \$931.0 million and \$930.8 million for the years ended December 31, 2019 and 2018, respectively. See Note 7 – *Investments in Unconsolidated Affiliates* for additional information.

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 December 31, 2019, we had \$1.6 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 future periods as follows (in thousands):

Year	Estimated Revenue
2020.....	\$ 398,647
2021.....	287,026
2022.....	281,798
2023.....	245,006
2024.....	206,499
Thereafter.....	218,956
Total.....	<u>\$ 1,637,932</u>

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 and the uncertainty related to the consideration is resolved each month as the distinct service is provided, we do not estimate the total variable consideration for the single overall performance obligation. 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 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, in the Gathering, Processing & Terminalling segment under certain water business services contracts subject to minimum volume commitments. We receive deficiency payments for volumes committed by the customer in a month but not physically delivered to the customer or received by us for disposal. These deficiencies are charged at the contracted rate per barrel and recorded as a contract liability until the barrels are received from the customer for disposal, or when the likelihood that the customer will utilize the deficiency balance becomes remote.

Balances associated with our contracts with customers were as follows:

	Contract Liabilities
	(in thousands)
Balance at January 1, 2018	\$ 88,471
Additions	34,613
Amounts recognized as revenue	(11,989)
Balance at December 31, 2018	111,095
Additions	35,923
Amounts recognized as revenue	(19,086)
Balance at December 31, 2019	\$ 127,932

	December 31, 2019	December 31, 2018	January 1, 2018
	(in thousands)		
Accounts receivable from contracts with customers. \$	80,756	\$ 80,935	\$ 61,888
Other accounts receivable ⁽¹⁾	226,756	151,414	56,727
Receivable from related parties.....	16,769	3,748	1,340
Accounts receivable, net	<u>\$ 324,281</u>	<u>\$ 236,097</u>	<u>\$ 119,955</u>

⁽¹⁾ Other accounts receivable primarily consists of receivables under crude oil forward purchase and sale arrangements that are accounted for as derivatives under ASC 815.

13. Leases

We account for leases in accordance with ASC Topic 842, Leases, which we adopted on January 1, 2019, applying the modified retrospective transition approach as of the effective date of adoption. See Note 2 – *Summary of Significant Accounting Policies* for additional information regarding the impacts of adoption.

We enter into operating leases as lessee for certain office space and equipment. We also have a capital lease agreement to lease the land site on which PLT expects to construct storage and terminalling facilities. In November 2018, we entered into a joint venture agreement with DHIF to jointly own PLT, an entity formed with the intention of developing a storage and terminalling facility. At the same time, PLT entered into an agreement with the Plaquemines Port & Harbor Terminal District to lease the land site on which PLT expects to construct the facilities.

Under ASC 842, a contract is or contains a lease when, (1) the contract contains an explicitly or implicitly identified asset and (2) the customer obtains substantially all of the economic benefits from the use of that underlying asset and directs how and for what purpose the asset is used during the term of the contract in exchange for consideration. We assess whether an arrangement is or contains a lease at inception of the contract. For all leases (finance and operating leases), other than those that qualify for the short-term recognition exemption, we recognize as of the lease commencement date on the balance sheet a liability for our obligation related to the lease and a corresponding asset representing our right to use the underlying asset over the period of use. The discount rate used to calculate the present value of the future minimum lease payments is the rate implicit in the lease, when readily determinable. As our leases do not provide an implicit rate, we determine the appropriate discount rate using our incremental secured borrowing rate, with consideration given to the nature and term of the leased asset.

Our leases have remaining terms of up to approximately 39 years. Certain of our lease agreements contain options to extend or early terminate the agreement. The lease term used to calculate the lease asset and liability at commencement includes options to extend or terminate the lease when it is reasonably certain that we will exercise that option. When determining whether it is reasonably certain that we will exercise an option at commencement, we consider various economic factors, including operating strategies, the nature, length, and underlying terms of the agreement, as well as the uncertainty of the condition of leased equipment at the end of the lease term. Based on these determinations, we generally determine that the exercise of renewal options would not be reasonably certain in determining the expected lease term.

For the years ended December 31, 2019, 2018, and 2017 operating lease cost was \$1.6 million, \$0.8 million, and \$9.1 million, respectively. For the year ended December 31, 2019, cash paid included in operating cash flows was \$1.5 million. During these periods the existing finance lease did not have any lease payments.

Supplemental information related to our existing leases as of December 31, 2019 was as follows:

	Balance Sheet Location	December 31, 2019
		(in thousands, except lease term and discount rate)
Operating Leases:		
Operating lease right-of-use assets	Deferred charges and other assets.....	\$ 12,629 ⁽¹⁾
Current operating lease liabilities	Other current liabilities	\$ 1,497 ⁽¹⁾
Non-current operating lease liabilities.....	Other long-term liabilities and deferred credits	\$ 11,231 ⁽¹⁾
Finance Leases:		
Finance lease right-of-use asset ⁽²⁾	Property, plant and equipment, net	\$ 30,704
Weighted Average Remaining Lease Term:		
Operating leases		15.3 years
Finance leases		38.9 years
Weighted Average Discount Rate:		
Operating leases		5.82%
Finance leases		7.01%

- (1) Includes right-of-use asset of approximately \$9.0 million and current and non-current lease liabilities of \$0.1 million and \$8.9 million, respectively, related to Guernsey Terminal capacity that we lease from Powder River Gateway.
- (2) PLT satisfied the initial capital lease obligation of \$30.7 million at lease inception and as a result has no outstanding liability or imputed interest on the future minimum rental commitments.

Maturities of lease liabilities as of December 31, 2019 were as follows:

Year	Operating Leases	Finance Leases ⁽¹⁾
	(in thousands)	
2020	\$ 2,247	\$ 449
2021	1,561	449
2022	1,021	449
2023	946	449
2024	910	467
Thereafter	13,644	17,303
Total lease payments	20,329	19,566
Less: discounting for present value and other adjustments	(7,601)	(19,566)
Present value of lease liabilities	\$ 12,728	\$ —

- (1) Future lease payments for finance leases consist of the annual payments under the PLT land site lease. At lease inception, the present value of the future lease payments exceeded the fair value of the leased property. As a result, the right of use asset and capital lease obligation were recorded at the \$30.7 million fair value of land. On that date, PLT made a payment of \$30.7 million, immediately relieving the capital lease obligation. As a result, PLT does not have an outstanding capital lease obligation or impute interest on the future minimum rental commitments and will account for the future lease payments in the period in which they are made.

Under various lease agreements, Tallgrass Midstream, LLC ("TMID"), as lessor, leases capacity on NGL pipelines that were constructed for third parties, and Deeprock Development, as lessor, leases capacity at certain of its storage facilities. Rental income for these arrangements was approximately \$9.4 million, \$10.9 million, and \$3.8 million for the years ended December 31, 2019, 2018, and 2017 respectively, and was recorded as "Processing and other revenues" in the accompanying consolidated statements of income. Under a lease agreement initially effective November 13, 2012, Tallgrass Interstate Gas Transmission, LLC ("TIGT"), as lessor, leases a portion of its office space to a third party. Rental income was approximately

\$0.7 million, \$0.8 million, and \$0.8 million for the years ended December 31, 2019, 2018, and 2017, respectively, and was recorded as "Other income (expense), net" in the accompanying consolidated statements of income.

At December 31, 2019, future minimum rental income under non-cancelable operating leases as the lessor were as follows:

Year	Total
	(in thousands)
2020.....	\$ 5,613
2021.....	3,773
2022.....	3,773
2023.....	3,773
2024.....	3,773
Thereafter	3,580
Total.....	<u>\$ 24,285</u>

Information as of December 31, 2018 under historical lease accounting guidance:

At December 31, 2018, our future minimum rental commitments under major, non-cancelable leases were as follows:

Year	Operating Leases	Capital Lease
	(in thousands)	
2019.....	\$ 1,074	\$ 449
2020.....	922	449
2021.....	483	449
2022.....	240	449
2023.....	147	449
Thereafter	364	17,770
Total.....	<u>\$ 3,230</u>	<u>\$ 20,015</u>

14. Commitments & Contingent Liabilities

See Note 13 – *Leases* for discussion regarding obligations under operating and finance leases.

Other Purchase Obligations

At December 31, 2019, future minimum commitments under long-term, non-cancelable contracts for service contracts, right of way ("ROW") agreements not accounted for as leases, and other purchase obligations were as follows (in thousands):

Year	Total
2020.....	\$ 16,260
2021.....	6,618
2022.....	5,753
2023.....	4,823
2024.....	2,141
Thereafter	20,255
Total.....	<u>\$ 55,850</u>

Capital Expenditures

We had committed approximately \$25.5 million for the future purchase of property, plant and equipment at December 31, 2019.

15. Net Income per Class A Share

Basic net income per Class A share is determined by dividing net income attributable to TGE by the weighted average number of outstanding Class A shares during the period. Class B shares do not share in the earnings of TGE. Accordingly, basic and diluted net income per Class B share has not been presented.

Diluted net income per Class A share is determined by dividing net income attributable to TGE by the weighted average number of outstanding diluted Class A shares during the period. For purposes of calculating diluted net income per Class A share, we considered the impact of possible future exercises of the Exchange Right by the Exchange Right Holders on both net income attributable to TGE and the diluted weighted average number of Class A shares outstanding. The Exchange Right Holders refers to the group of persons who collectively own all of TGE's outstanding Class B shares and an equivalent number of TE Units. The Exchange Right Holders are entitled to exercise the right to exchange their TE Units (together with an equivalent number of Class B shares) for Class A shares at an exchange ratio of one Class A share for each TE Unit exchanged, which we refer to as the Exchange Right. As of December 31, 2019, the Exchange Right Holders primarily consist of certain of the Sponsor Entities and certain current and former members of our management.

Pursuant to the TGE partnership agreement and the Tallgrass Equity limited liability company agreement, our capital structure and the capital structure of Tallgrass Equity will generally replicate one another in order to maintain the one-for-one exchange ratio between the TE Units and Class B shares, on the one hand, and our Class A shares, on the other hand. As a result, the exchange of any Class B shares for Class A shares does not have a dilutive effect on basic net income per Class A share. However, for the years ended December 31, 2019 and 2018, the assumed issuance of TGE Equity Participation Shares would have had a dilutive effect on basic net income per Class A share as shown in the table below. The potential issuance of TGE Equity Participation Shares would not have had a dilutive effect on the basic net loss per Class A share for the year ended December 31, 2017.

The following table illustrates the calculation of net income per Class A share for the years ended December 31, 2019, 2018, and 2017:

	Year Ended December 31,		
	2019	2018	2017
	(in thousands, except per unit amounts)		
Basic Net Income per Class A Share:			
Net income (loss) attributable to TGE	\$ 248,809	\$ 137,127	\$ (128,729)
Basic weighted average Class A Shares outstanding	174,816	107,586	58,076
Basic net income (loss) per Class A share.....	<u>\$ 1.42</u>	<u>\$ 1.27</u>	<u>\$ (2.22)</u>
Diluted Net Income per Class A Share:			
Net income (loss) attributable to TGE	\$ 248,809	\$ 137,127	\$ (128,729)
Incremental net income attributable to TGE including the effect of the assumed issuance of Equity Participation Shares.....	1,137	2,108	—
Net income (loss) attributable to TGE including incremental net income from assumed issuance of Equity Participation Shares	<u>\$ 249,946</u>	<u>\$ 139,235</u>	<u>\$ (128,729)</u>
Basic weighted average Class A Shares outstanding	174,816	107,586	58,076
Equity Participation Shares equivalent shares	1,684	2,231	—
Diluted weighted average Class A Shares outstanding	<u>176,500</u>	<u>109,817</u>	<u>58,076</u>
Diluted net income (loss) per Class A Share.....	<u>\$ 1.42</u>	<u>\$ 1.27</u>	<u>\$ (2.22)</u>

16. Major Customers and Concentration of Credit Risk

During the years ended December 31, 2019, 2018, and 2017, one non-affiliated customer, Continental Resources, Inc. ("Continental Resources"), accounted for \$85.4 million (10%), \$81.9 million (10%), and \$100.2 million (15%), of our total operating revenues, respectively. Revenues from Continental Resources for the years ended December 31, 2019 and 2018 were earned in our Crude Oil Transportation and Gathering, Processing & Terminalling segments. Revenues from Continental Resources for the year ended December 31, 2017 were earned in our Crude Oil Transportation segment.

For the year ended December 31, 2019, the percentage of segment revenues from the top ten non-affiliated customers for each segment was as follows:

	Percentage of Segment Revenue
Natural Gas Transportation	55%
Crude Oil Transportation	80%
Gathering, Processing & Terminalling	50%

We attempt to mitigate credit risk by seeking credit support, such as letters of credit, prepayments or other financial guarantees from customers with specific credit concerns.

17. Equity-Based Compensation

Long-term Incentive Plan

We have two long-term incentive plans. The Tallgrass Energy GP, LLC Long-Term Incentive Plan (f/k/a the TEGP Management, LLC Long-Term Incentive Plan), was originally adopted by our general partner effective as of May 1, 2015, and was amended and restated effective August 2, 2018 (as amended, the "TGE LTIP"). In addition, the Tallgrass MLP GP, LLC Long-Term Incentive Plan was originally adopted by TEP GP effective as of May 13, 2013, and was amended and restated effective August 2, 2018 (as amended, the "Legacy LTIP" and together with the TGE LTIP, the "Plans"). In connection with the completion of the TEP Merger effective June 30, 2018, the Legacy LTIP was assumed by our general partner.

Awards under the Plans may consist of, among others, unrestricted shares, restricted shares, equity participation shares, options and share appreciation rights which may be granted to (i) the employees of our general partner and its affiliates who perform services for us, (ii) the non-employee directors of our general partner and (iii) the consultants who perform services for us. The TGE LTIP limits the number of shares that may be delivered pursuant to awards to 3,144,589 Class A shares, and the Legacy LTIP limits the number of shares that may be delivered pursuant to awards under such plan to 20,000,000 Class A shares, subject in each case to any adjustment due to recapitalization, reorganization or a similar event permitted under the applicable Plan. Shares that are forfeited or withheld to satisfy exercise price or tax withholding obligations are available for delivery pursuant to other awards under the applicable Plan. The Plans are administered by the board of directors of our general partner or a committee thereof, which is referred to as the plan administrator.

Equity Participation Shares

Vesting of the Equity Participation Shares granted to date is contingent on certain service and, in some cases, performance conditions. The Equity Participation Shares are non-participating; as such participants are not entitled to receive any dividends with respect to the Equity Participation Shares unless the participant receives a separate grant of Distribution Equivalent Rights. At this time, no grants of Distribution Equivalent Rights have been made.

The Equity Participation Share grants under the Plans are measured at their grant date fair value. The Equity Participation Shares are non-participating; therefore, the grant date fair value is discounted from the grant date fair value of TGE's Class A shares for the present value of the expected future dividends during the vesting period. Effective June 30, 2018 with the completion of the TEP Merger, as discussed in Note 1 – *Description of Business*, TEP's outstanding Equity Participation Units were converted to Equity Participation Shares at a ratio of 2.0 Equity Participation Shares for each outstanding TEP Equity Participation Unit. Total equity-based compensation cost related to the Equity Participation Share grants was approximately \$31.6 million, \$7.6 million, and \$1.6 million for the years ended December 31, 2019, 2018, and 2017 respectively, excluding costs associated with TEP's Equity Participation Units prior to the TEP Merger. As of December 31, 2019, \$60.0 million of total compensation cost related to non-vested Equity Participation Shares is expected to be recognized over a weighted-average period of 3.7 years.

The March 2019 Blackstone Acquisition discussed in Note 1 – *Description of Business* constituted a change in control event under certain Equity Participation Share agreements outstanding under the LTIP plan, resulting in the accelerated vesting of 1,092,637 Class A shares (net of tax withholding of approximately 543,909 Class A shares) with a weighted average grant date fair value of \$18.82. These Class A shares were issued in April 2019. The accelerated vesting resulted in the recognition of equity-based compensation costs of \$12.5 million in "General and administrative" costs in the consolidated statements of income during the year ended December 31, 2019.

The following table summarizes the changes in the Equity Participation Shares outstanding for the years ended December 31, 2019, 2018 and 2017:

	Equity Participation Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2017	205,000	\$ 25.83
Granted	30,000	23.66
Vested.....	(10,002)	(14.26)
Outstanding at December 31, 2017	224,998	25.91
Granted	1,138,200	17.01
Converted ⁽¹⁾	1,786,310	18.20
Vested.....	(20,664)	(19.19)
Forfeited.....	(79,200)	(20.62)
Outstanding at December 31, 2018	3,049,644	18.25
Granted	3,204,850	18.14
Vested ⁽²⁾	(2,316,294)	(18.75)
Forfeited.....	(55,200)	(17.18)
Outstanding at December 31, 2019	3,883,000	\$ 17.85

⁽¹⁾ Reflects TEP's outstanding Equity Participation Units that were converted to Equity Participation Shares at a ratio of 2.0 Equity Participation Shares for each outstanding TEP Equity Participation Unit upon completion of the TEP Merger as discussed above.

⁽²⁾ Includes the accelerated vesting of 1,478,986 Class A shares (net of tax withholding of approximately 707,560 Class A shares) upon the change in control event as discussed above and other 2019 transactions.

18. Income Taxes

Income tax expense is estimated using the tax rate in effect or to be in effect during the relevant periods in the jurisdictions in which we operate. Deferred income tax assets and liabilities are recognized for temporary differences between the basis of assets and liabilities for financial reporting and tax purposes and are stated at enacted tax rates expected to be in effect when taxes are actually paid or recovered. To the extent we do not consider it more likely than not that a deferred tax asset will be recovered, a valuation allowance is established. We record a valuation allowance to reduce our deferred tax assets to the amount we believe is more likely than not to be realized. In making these determinations we consider historical and projected taxable income, and ongoing prudent and feasible tax planning strategies, in assessing the appropriateness of a valuation allowance. Changes in tax legislation are included in the relevant computations in the period in which such changes are effective.

U.S. Federal and State Taxes

Although we are organized as a limited partnership, we have elected to be treated as a corporation for U.S. federal income tax purposes and are therefore subject to both U.S. federal and state income taxes. We are projecting a loss for both U.S. federal and state income taxes for the tax year ended December 31, 2019. As a result, TGE has no current provision for income taxes for the year ended December 31, 2019, however, as discussed below one of our consolidated subsidiaries recognized current income tax expense during the year ended December 31, 2019.

Tax Components

Components of income tax expense are as follows:

	Year Ended December 31,		
	2019	2018	2017
	(in thousands)		
Current income tax expense:			
Federal income tax	\$ 728 ⁽¹⁾	\$ —	\$ —
Deferred income tax expense:			
Federal income tax	65,009	41,585	200,787
State income tax	4,856	14,124	7,671
Total deferred income tax expense	69,865	55,709	208,458
Total income tax expense	<u>\$ 70,593</u>	<u>\$ 55,709</u>	<u>\$ 208,458</u>

- ⁽¹⁾ As discussed in Note 3 – *Acquisitions and Dispositions*, a newly formed indirect subsidiary of TGE acquired the outstanding stock of an entity classified as a C corporation for U.S. federal income tax purposes effective May 1, 2019. As a result, we recognized approximately \$0.7 million of current income taxes during the year ended December 31, 2019.

The difference between tax expense based on the statutory federal income tax rate and our effective tax expense is summarized as follows:

	Year Ended December 31,		
	2019	2018	2017
	(in thousands)		
Net income before tax	\$ 519,148	\$ 523,380	\$ 432,443
Less: Net income attributable to noncontrolling interests	(199,746)	(330,544)	(352,714)
Net income subject to tax	\$ 319,402	\$ 192,836	\$ 79,729
Federal statutory income tax rate	21%	21%	35%
Income tax at statutory rate	\$ 67,074	\$ 40,496	\$ 27,905
State income taxes, net of federal benefit	8,413	5,419	2,392
Change in state tax rate	1,214	8,705	1,353
Valuation allowance	(4,771)	—	3,926
Other	(1,337)	1,089	—
Total income tax expense before change in tax legislation	\$ 70,593	\$ 55,709	\$ 35,576
Impact of federal tax legislation on deferred tax asset	—	—	172,037
Impact of federal tax legislation on valuation allowance	—	—	845
Total income tax expense	<u>\$ 70,593</u>	<u>\$ 55,709</u>	<u>\$ 208,458</u>
Effective tax rate	<u>13.6%</u>	<u>10.6%</u>	<u>48.2%</u>

Deferred tax assets result from the following:

	December 31, 2019	December 31, 2018
	(in thousands)	
Deferred tax assets:		
Investment in partnerships	\$ 149,336	\$ 198,290
Net operating losses	168,866	80,012
Deferred tax assets before valuation allowance	\$ 318,202	\$ 278,302
Valuation allowance	—	(4,771)
Total deferred tax assets	<u>\$ 318,202</u>	<u>\$ 273,531</u>
Deferred tax liabilities:		
Equity earnings adjustment pursuant to ASC 606	\$ 523	\$ 817
Property, plant & equipment in corporate subsidiary	8,207	—
Total deferred tax liabilities	<u>\$ 8,730</u>	<u>\$ 817</u>

On May 12, 2015, as a result of the transfer of the ownership interest in Tallgrass Equity as part of the Reorganization Transactions in connection with the TGE IPO, we recognized a deferred tax asset of \$445.2 million. During 2018, a portion of the Exchange Right Holders exercised their Exchange Right as discussed in Note 11 – *Partnership Equity*. In connection with the resulting transfer of TE Units, we recognized an additional deferred tax asset of \$15.4 million. During 2019, we recognized an additional deferred tax asset of \$115.4 million upon exercise of the Exchange Right, as discussed in Note 11 – *Partnership Equity*, with respect to 21,751,018 Class B shares to Class A shares in connection with the March 2019 Blackstone Acquisition discussed in Note 1 – *Description of Business*. These transfers of ownership were accounted for at the historical carrying basis for GAAP accounting purposes, but recorded at the value of the consideration paid for U.S. federal income tax purposes. The tax rates that apply when the deferred tax balances ultimately reverse are inherent in the realization of the deferred tax balances. State tax rates can change from year to year based upon changes in both state apportionment percentages and state tax laws.

As of December 31, 2019, we had a federal net operating loss carry forward of \$697.6 million and various state net operating loss carry forwards. The determination of the state net operating loss carry forwards is dependent upon apportionment percentages and state laws that can change from year to year and impact the amount of such carry forwards. If not utilized, the federal net operating loss carry forward will expire between 2035 and 2037 (net operating losses generated in tax years beginning after December 31, 2017 can be carried forward indefinitely) and the state operating loss carry forwards will expire between 2025 and 2039. During the year ended December 31, 2019, we released the previously recorded valuation allowance of \$4.8 million, as it is more likely than not that the deferred tax assets related to federal and state net operating losses will be realized.

On December 22, 2017, legislation referred to as the "Tax Cuts and Jobs Act" ("TCJA") was signed into law. Substantially all provisions of the TCJA are effective for taxable years beginning after December 31, 2017. The TCJA includes amendments to the Internal Revenue Code of 1986, that significantly change the taxation of individuals and business entities. Pursuant to ASC Topic 740, Income Taxes (ASC 740), we recognized the tax effect of the TCJA changes during the year ended December 31, 2017, the period in which the law was enacted. ASC 740 requires deferred tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. Accordingly, we remeasured our deferred tax asset based on the new tax rates, resulting in an increase to our tax provision of \$172.9 million for the year ended December 31, 2017.

The 2016 through 2019 tax years are open to examination for federal and state income tax.

19. Regulatory Matters

Ratemaking Process - Natural Gas Transportation & Storage

Transportation and storage services on interstate natural gas pipelines are contracted under one of three rate types: recourse, discount, or negotiated. Recourse rates are calculated based on the cost of service being provided and include an allowable rate of return for the pipeline. Recourse rates are established through a FERC rate proceeding and remain effective until a subsequent rate proceeding is filed and approved by the FERC. Discount rates are offered at a discount to the then-effective maximum recourse rate. Discount rates are typically effective for an established term and can vary based on movement of the underlying recourse rate. Negotiated rates can be higher or lower than the then-effective maximum recourse

rate, subject to agreement between the pipeline and shipper and approval by the FERC. Negotiated rates are also entered into for a defined term but do not change based on adjustments in the applicable recourse rate for that type of service.

On May 1, 2019, TIGT filed with the FERC a pre-filing settlement in Docket No. RP19-423-001 that establishes, among other things, settlement rates reflecting an overall decrease to recourse rates, contract extensions for maximum recourse rate firm contracts through May 31, 2023, and a rate moratorium period through May 31, 2023. The settlement also requires that TIGT file a new general rate case pursuant to Section 4 of the Natural Gas Act ("NGA") on June 1, 2023, provided that TIGT has not preempted this mandatory filing requirement by filing on or before June 1, 2023 for approval of a new pre-filing settlement. The settlement also provided for contract extensions for maximum recourse rate firm contracts through May 31, 2023 and established a rate moratorium that will result in TIGT filing a new rate case or pre-filing settlement on or before June 1, 2023. TIGT's settlement was approved on November 8, 2019 in an order issued by the FERC.

On June 29, 2018, Trailblazer Pipeline filed a general rate case with the FERC pursuant to Section 4 of the NGA in Docket No. RP18-922-000. Trailblazer and its customers reached a settlement in principle on October 2, 2019. The settlement continues the bifurcated rate treatment for Trailblazer's "Existing System" and "Expansion System" and maintains the existing fuel retainage and revenue crediting mechanisms. Shippers with firm contracts on the Existing System were given the opportunity to convert their contracts to negotiated rate agreements that would terminate no earlier than December 31, 2026. A rate moratorium will be in effect through December 31, 2025. The settlement was filed with the FERC on December 20, 2019 and is currently awaiting approval from the FERC.

The majority of services provided by Rockies Express are contracted under negotiated rate agreements. Currently, there are no regulatory proceedings challenging the transportation rates of Rockies Express.

Ratemaking Process - Crude Oil Transportation

Pony Express has three types of transportation rates on its system. The first are contract rates, which are contractually agreed to and given in exchange for either commitments to ship on the pipeline or acreage dedications ("Contract Rates"). Contract Rates are generally honored by the FERC during the term of the relevant contracts. The majority of Pony Express' revenue is derived from Contract Rates. The second are indexed rates, which means they may be increased or decreased at any time provided they do not exceed the index ceiling ("Indexed Rates"). The index ceiling is calculated yearly by applying the FERC-approved inflationary adjustment, which may be positive or negative. These rates can be challenged on a cost-of-service basis. Pony Express last adjusted its Indexed Rates in Docket No. IS19-638-000 effective July 1, 2019. The third are volume incentive rates, which reflect a discount to the Indexed Rates and are available to all shippers without a contractual commitment to ship on the pipeline ("Volume Incentive Rates"). These discounts are discretionary and may not be challenged on a cost-of-service basis; however, should Pony Express' Indexed Rates be lowered due to a cost-of-service challenge, the Volume Incentive Rates would also be reduced if they are no longer below the Indexed Rates. Pony Express established its first Volume Incentive Rates effective November 1, 2019 in Docket No. IS20-3-000. Currently, there are no regulatory proceedings challenging transportation rates at Pony Express.

Powder River Gateway's crude oil pipeline systems operate with Contract Rates and Indexed Rates, which can be challenged on a cost-of-service basis. Currently, there are no regulatory proceedings challenging transportation rates at Powder River Gateway.

In 2020, the FERC will conduct its five-year index review to establish the new FERC approved adder, which will be in effect for the five-year period beginning July 1, 2021. The 2020 review will also consider, among other things, the effects of the Tax Cuts and Jobs Act of 2017 and any applicable impact on a crude oil pipeline's cost of service.

Other Regulatory Matters

In addition to the ratemaking proceedings discussed above, we have also made certain other regulatory filings with the FERC, including those further described below:

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.

Rockies Express Cheyenne Hub Enhancement Project - FERC Docket No. CP18-103-000

On March 2, 2018, Rockies Express submitted an application pursuant to section 7(c) of the NGA 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 further described below. On December 18, 2018, the FERC issued the Environmental Assessment. On September 20, 2019, the FERC issued an order approving the application. A notice to proceed with construction was issued on October 8, 2019.

Cheyenne Connector Pipeline - FERC Docket No. CP18-102-000

On March 2, 2018, Cheyenne Connector submitted an application pursuant to section 7(c) of the NGA 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' Cheyenne Hub. On September 20, 2019, the FERC issued an order approving the application. A notice to proceed with construction was issued on October 8, 2019.

20. Legal and Environmental Matters

Legal

In addition to the matters discussed below, we are involved 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 matters 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 December 31, 2019 or 2018.

Rockies Express

EM Energy Ohio, LLC

On May 15, 2019, EM Energy Ohio, LLC ("EM Energy") and certain of its affiliates filed for protection under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware. EM Energy had a firm transportation service agreement with Rockies Express for 50,000 Dth/d through January 5, 2032. Rockies Express and EM Energy have stipulated in the bankruptcy proceeding that the termination date of the transportation service agreement is June 13, 2019. Following the termination, Rockies Express made a drawing equal to the outstanding face amount on the letter of credit supporting EM Energy's obligations under the transportation service agreement and received approximately \$16.2 million in June 2019. A portion of the proceeds was used to settle outstanding accounts receivable for transportation services provided to EM Energy and the remaining \$13.9 million was recognized as income by Rockies Express. Rockies Express intends to pursue its claim against the bankruptcy estate of EM Energy for damages and to remarket the capacity resulting from the termination of the transportation service agreement.

Ohio Public Utility Excise Tax

The Ohio Tax Commissioner has assessed Rockies Express a public utility excise tax on transactions concerning product that entered and exited the Rockies Express Pipeline within the State of Ohio. This tax applies to gross receipts from all business conducted within the state, but exempts all receipts derived wholly from interstate business. Rockies Express disputed its obligation to pay Ohio's public utility excise tax under the relevant Ohio statute, but made payments in the amounts assessed in order to preserve its right to appeal. On February 11, 2020, the Ohio Supreme Court reached a final decision adverse to the position taken by Rockies Express.

As a result of this decision, Rockies Express no longer believes that the refund of prior payments is probable and accordingly has recognized expense totaling \$15.8 million during the year ended December 31, 2019. The expense recognized represents payments made to the state of Ohio totaling \$12.3 million and an additional \$3.5 million for amounts expected to be assessed for the period from May 1, 2019 through December 31, 2019.

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. We received our proportionate distribution from the cash settlement payment in July 2017.

Michels Corporation

On June 17, 2014, Michels Corporation ("Michels") filed a complaint and request for relief against Rockies Express in the Court of Common Pleas, Monroe County, Ohio, as a result of work performed by Michels to construct the Seneca Lateral Pipeline in Ohio. Michels sought unspecified damages from Rockies Express and asserted claims of breach of contract, negligent misrepresentation, unjust enrichment and quantum meruit. Michels also filed notices of Mechanic's Liens in Monroe and Noble Counties, asserting \$24.2 million as the amount due.

On February 2, 2017, Rockies Express and Michels agreed to resolve Michels' claims for a \$10 million cash payment by Rockies Express. The cash payment was inclusive of approximately \$5.9 million that Rockies Express had been withholding from Michels. Subsequently, Rockies Express and Michels entered into a definitive agreement with respect to the settlement and Rockies Express made the \$10 million cash payment to Michels on February 16, 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 currently 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 \$6.3 million and \$7.4 million at December 31, 2019 and 2018, respectively.

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. Permanent repairs were completed in September 2018. Total cost of remediation was approximately \$6.1 million, \$5.1 million of which Rockies Express has recovered through insurance.

TMID and TIGT

Casper Gas 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, 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. TMID and TIGT entered into a Consent Agreement and Final Order to settle this matter with the EPA on February 21, 2019 and made an approximately \$0.1 million penalty payment to the EPA.

Casper Gas Plant, WDEQ Notice of Violation

On November 25, 2014, the 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. TMID and TIGT entered into a Consent Decree to settle this matter with the WDEQ on March 8, 2019 and made an approximately \$0.1 million penalty payment to the WDEQ.

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 continued performing remediation to increase and maximize its operating capacity over the long-term and spent approximately \$21 million during 2018 for this pipe replacement and remediation work. As of October 2018, the pipeline was returned to its maximum allowable operating capacity.

In connection with TEP's 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 was substantially complete as of March 31, 2018.

Terminals

System Failures

In January 2017, approximately 10,000 bbls of crude oil were released at the Sterling Terminal as the result of a defective roof drain system on a storage tank. The release was restricted to the containment area designed for such purpose and approximately 9,000 bbls were recovered. Remediation was complete as of June 30, 2017. The total cost to remediate the release was approximately \$600,000.

21. 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. 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 Senior Notes, public company costs, equity-based compensation expense, and eliminations of intersegment activity.

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 75% 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 Crude Oil Transportation segment includes our 51% membership interest in Powder River Gateway.

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. The Gathering, Processing, & Terminalling segment includes our 51% membership interest in Pawnee Terminal, LLC ("Pawnee Terminal").

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 to be 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 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 and deficiency payments received from or utilized by our customers. Adjusted EBITDA is calculated and presented at the Tallgrass Equity level, before consideration of noncontrolling interest associated with the Exchange Right Holders, which we believe provides investors the most complete and comparable picture of our overall financial and operational results.

The following tables set forth our segment information for the periods indicated:

Revenue:	Year Ended December 31,								
	2019			2018			2017		
	Total Revenue	Inter-Segment	External Revenue	Total Revenue	Inter-Segment	External Revenue	Total Revenue	Inter-Segment	External Revenue
	(in thousands)								
Natural Gas Transportation.....	\$139,752	\$ (2,179)	\$137,573	\$140,459	\$ (4,661)	\$135,798	\$141,021	\$ (6,694)	\$134,327
Crude Oil Transportation.....	486,647	(57,881)	428,766	444,454	(39,319)	405,135	364,574	(10,676)	353,898
Gathering, Processing & Terminalling	335,895	(33,686)	302,209	279,665	(27,339)	252,326	186,211	(18,538)	167,673
Corporate and Other	—	—	—	—	—	—	—	—	—
Total revenue	<u>\$962,294</u>	<u>\$(93,746)</u>	<u>\$868,548</u>	<u>\$864,578</u>	<u>\$(71,319)</u>	<u>\$793,259</u>	<u>\$691,806</u>	<u>\$(35,908)</u>	<u>\$655,898</u>

Tallgrass Equity Adjusted EBITDA:	Year Ended December 31,								
	2019			2018			2017		
	Total Adjusted EBITDA	Inter- Segment	External Adjusted EBITDA	Total Adjusted EBITDA	Inter- Segment	External Adjusted EBITDA	Total Adjusted EBITDA	Inter- Segment	External Adjusted EBITDA
(in thousands)									
Natural Gas Transportation	\$543,507	\$ (4,707)	\$ 538,800	\$377,224	\$(4,251)	\$372,973	\$180,978	\$(2,176)	\$178,802
Crude Oil Transportation	344,333	(19,903)	324,430	239,330	(8,147)	231,183	140,785	4,878	145,663
Gathering, Processing & Terminalling	121,159	24,610	145,769	59,203	12,398	71,601	16,083	(2,702)	13,381
Corporate and Other	(12,666)	—	(12,666)	(21,321)	—	(21,321)	(37,591)	—	(37,591)
Reconciliation to Net Income:									
<i>Add:</i>									
Equity in earnings of unconsolidated investments ⁽¹⁾			325,385			237,197			66,922
(Loss) gain on disposal of assets ⁽¹⁾ ..			(354)			4,630			189
Non-cash (loss) gain related to derivative instruments ⁽¹⁾			(272)			3,340			(64)
Other non-cash gain			724			—			—
Gain on remeasurement of unconsolidated investment ⁽¹⁾			—			—			2,744
<i>Less:</i>									
Interest expense, net ⁽¹⁾			(161,429)			(95,465)			(29,403)
Depreciation and amortization expense ⁽¹⁾			(127,503)			(74,998)			(26,131)
Distributions from unconsolidated investments ⁽¹⁾			(470,981)			(302,364)			(86,551)
Non-cash compensation expense ⁽¹⁾			(31,563)			(8,634)			(2,682)
Deficiency payments, net ⁽¹⁾			(16,992)			(14,443)			(7,701)
Loss on debt retirement			—			(2,245)			—
Income tax expense			(70,578)			(55,709)			(208,458)
Net income attributable to Exchange Right Holders			(193,961)			(208,618)			(137,849)
Net income (loss) attributable to TGE..			<u>\$248,809</u>			<u>\$137,127</u>			<u>\$128,729</u>

⁽¹⁾ Net of noncontrolling interest associated with less than wholly-owned subsidiaries of Tallgrass Equity.

Capital Expenditures:	Year Ended December 31,		
	2019	2018	2017
	(in thousands)		
Natural Gas Transportation	\$ 86,892	\$ 112,529	\$ 16,705
Crude Oil Transportation.....	94,363	65,745	57,022
Gathering, Processing & Terminalling.....	96,168	185,732	71,417
Corporate and Other	8,230	4,867	—
Total capital expenditures.....	<u>\$ 285,653</u>	<u>\$ 368,873</u>	<u>\$ 145,144</u>

Unconsolidated Investments:	December 31, 2019	December 31, 2018
	(in thousands)	
Natural Gas Transportation	\$ 1,811,051	\$ 1,794,987
Crude Oil Transportation.....	164,773	35,467
Gathering, Processing & Terminalling.....	30,395	31,232
Total unconsolidated investments	<u>\$ 2,006,219</u>	<u>\$ 1,861,686</u>

Assets:	December 31, 2019	December 31, 2018
	(in thousands)	
Natural Gas Transportation	\$ 2,554,513	\$ 2,606,696
Crude Oil Transportation.....	1,734,278	1,423,740
Gathering, Processing & Terminalling.....	1,693,474	1,522,559
Corporate and Other	231,821	340,514
Total assets	<u>\$ 6,214,086</u>	<u>\$ 5,893,509</u>

22. Selected Quarterly Financial Data (Unaudited)

The following tables summarize our unaudited quarterly financial data for 2019 and 2018:

	Quarter Ended 2019			
	First	Second	Third	Fourth
	(in thousands, except per unit amounts)			
Total revenues.....	\$ 197,352	\$ 211,524	\$ 226,709	\$ 232,963
Operating income	\$ 70,464	\$ 89,596	\$ 105,866	\$ 86,834
Net income.....	\$ 102,392	\$ 126,230	\$ 128,489	\$ 91,444
Net income allocable to noncontrolling interests	\$ (51,805)	\$ (54,611)	\$ (55,965)	\$ (37,365)
Net income attributable to TGE.....	\$ 50,587	\$ 71,619	\$ 72,524	\$ 54,079
Basic net income per Class A Share	\$ 0.31	\$ 0.40	\$ 0.40	\$ 0.30
Diluted net income per Class A Share	\$ 0.31	\$ 0.40	\$ 0.40	\$ 0.30

	Quarter Ended 2018			
	First	Second	Third	Fourth
	(in thousands, except per unit amounts)			
Total revenues.....	\$ 179,094	\$ 193,589	\$ 200,320	\$ 220,256
Operating income	\$ 81,913	\$ 79,275	\$ 90,084	\$ 99,359
Net income.....	\$ 114,313	\$ 109,701	\$ 118,712	\$ 124,945
Net income allocable to noncontrolling interests	\$ (97,578)	\$ (108,638)	\$ (59,162)	\$ (65,166)
Net income attributable to TGE.....	\$ 16,735	\$ 1,063	\$ 59,550	\$ 59,779
Basic net income per Class A Share	\$ 0.29	\$ 0.02	\$ 0.38	\$ 0.38
Diluted net income per Class A Share	\$ 0.29	\$ 0.02	\$ 0.38	\$ 0.38

During the second quarter of 2018, we recognized increased deferred income tax expense as a result of our increased ownership in TEP due to the TEP Merger and the resulting increase in income allocated to TGE.

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosures

On March 11, 2019, PricewaterhouseCoopers LLP ("PwC") resigned as the independent registered public accounting firm of TGE and its subsidiaries. PwC's resignation resulted from its determination that, following the March 2019 Blackstone Acquisition, PwC no longer satisfies the independence requirement for continuing as our independent registered public accounting firm. For additional information regarding the March 2019 Blackstone Acquisition, see Note 1 – *Description of Business*.

The reports of PwC on the financial statements of TGE and its subsidiaries for the fiscal years ended December 31, 2018 and 2017 contain no adverse opinion or disclaimer of opinion and were not qualified or modified as to uncertainty, audit scope or accounting principle. During the fiscal years ended December 31, 2018 and 2017 and subsequent interim period through March 11, 2019, there were no disagreements with PwC on any matter of accounting principles or practices, financial statement disclosure or auditing scope or procedures, which disagreements if not resolved to PwC's satisfaction would have caused them to make reference thereto in their report on the financial statements for such years, nor were there any reportable events (as defined in Item 304(a)(1)(v) of Regulation S-K).

On April 9, 2019, the Audit Committee of the board of directors of our general partner engaged Deloitte & Touche LLP as our new independent registered public accounting firm, effective immediately. During our fiscal years ended December 31, 2018 and 2017 and during the subsequent interim period from January 1, 2019 through April 9, 2019, neither we nor anyone on our behalf consulted with Deloitte & Touche LLP on any matter that (i) involved the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on our financial statements, in each case where a written report was provided or oral advice was provided that Deloitte & Touche LLP concluded was an important factor considered by us in reaching a decision as to any accounting, auditing or financial reporting issue, or (ii) was either the subject of a "disagreement", as that term is defined in Item 304(a)(1)(iv) of Regulation S-K and the related instructions to Item 304 of Regulation S-K, or a "reportable event", as that term is defined in Item 304(a)(1)(v) of Regulation S-K.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Based upon their evaluation of those controls and procedures performed as of December 31, 2019, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act). Our internal control over financial reporting is a process designed under the supervision of our principal executive officer and principal financial officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our consolidated financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2019, our management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established in Internal Control - Integrated Framework (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment and those criteria, management determined that we maintained effective internal control over financial reporting as of December 31, 2019.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Our independent registered public accounting firm, Deloitte & Touche LLP, audited the effectiveness of our internal control over financial reporting as of December 31, 2019, as stated in their report included in Item 8.—Financial Statements and Supplementary Data of this Annual Report.

Changes in Internal Control over Financial Reporting

There have not been any 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 December 31, 2019 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

We are a limited partnership and have no officers or directors. Unless otherwise indicated, references to our officers and directors in Items 10 through 14 of this Annual Report refer to the officers and directors of our general partner.

Management of Tallgrass Energy, LP

Our general partner's board of directors and executive officers manage our operations and activities. Our general partner is not elected by our Class A shareholders and will not be subject to re-election in the future. Directors of our general partner oversee our operations. Unlike shareholders in a publicly traded corporation, Class A shareholders are not entitled to elect the directors of our general partner, and Class A shareholders do not otherwise directly or indirectly participate in our management or operations. The board of directors of our general partner, including our independent directors, is currently designated and elected by BIP through its control of our general partner subject only to certain contractual rights in the Equityholders Agreement entered into between certain affiliates of the Sponsor Entities and BIP's co-investors in March 2019 and limitations in the Take-Private Merger Agreement.

As of December 31, 2019, the board of directors of our general partner had eight directors, four of whom the board has determined meet the independence standards established by the NYSE. The four independent directors are Guy G. Buckley, Roy N. Cook, Thomas A. Gerke, and Terrance D. Towner. The NYSE does not require a publicly-traded limited partnership like ours to have a majority of independent directors on the board of directors of its general partner or to establish a compensation or a nominating and corporate governance committee. However, our general partner is required to have an audit committee of at least three members, and all its members are required to meet the independence and experience standards established by the NYSE and the Exchange Act. As of December 31, 2019, the audit committee of the board of directors of our general partner consisted of Messrs. Buckley, Cook, Gerke and Towner, each of whom meet the independence and experience standards established by the NYSE and the Exchange Act.

In evaluating director candidates, BIP assesses whether a candidate possesses the integrity, judgment, knowledge, experience, skill and expertise that are likely to enhance the board's ability to manage and direct our affairs and business, including, when applicable, to enhance the ability of committees of the board to fulfill their duties.

All the executive officers of our general partner are also officers of TEP GP and Tallgrass Equity. Our officers will devote such portion of their business time to our business and affairs as they deem reasonably required to manage and conduct our operations. Our general partner and its affiliates do not currently receive any management fee in connection with the management of our business, but Tallgrass Equity reimburses our general partner for all expenses it incurs and payments it makes on our behalf pursuant to our partnership agreement.

In addition, prior to the closing of the March 2019 Blackstone Acquisition, Tallgrass Equity reimbursed Tallgrass Energy Holdings and its affiliates for all expenses it incurred and payments it made on our behalf pursuant to the TGE Omnibus Agreement, including the costs of employee and director compensation and benefits as well as the cost of the provision of certain corporate, general and administrative services in each case to the extent properly allocable to us. The TGE Omnibus Agreement was terminated effective March 11, 2019 in connection with the closing of the March 2019 Blackstone Acquisition. For more information, see "*Certain Relationships and Related Party Transactions, and Director Independence-TGE Omnibus Agreement.*"

Directors and Executive Officers of Our General Partner

The following table sets forth certain information with respect to the executive officers and directors of our general partner as of February 12, 2020.

Name	Age	Position with Our General Partner
William R. Moler	54	Chief Executive Officer, Director; Former President and Chief Operating Officer
Matthew Sheehy	40	President
Gary J. Brauchle ⁽¹⁾	46	Executive Vice President and Chief Financial Officer
Christopher R. Jones	43	Executive Vice President, General Counsel and Secretary
Gary D. Watkins ⁽²⁾	47	Senior Vice President and Chief Accounting Officer
Marcelino Oreja Arburúa	50	Director
Guy G. Buckley	59	Director
Roy N. Cook	62	Director
Thomas A. Gerke	63	Director
Wallace C. Henderson	57	Director
Matthew J.K. Runkle	41	Director
Terrance D. Towner	61	Director

⁽¹⁾ Mr. Brauchle has informed the board of directors of our general partner of his resignation from his position as the Executive Vice President and Chief Financial Officer effective on February 14, 2020.

⁽²⁾ The board of directors of our general partner has appointed Mr. Watkins as Executive Vice President and Chief Financial Officer effective on February 14, 2020, in addition to Mr. Watkins' current role as Chief Accounting Officer of our general partner.

Our directors hold office until the earlier of their death, resignation, removal or disqualification or until their successors are duly elected or qualified. Officers serve at the discretion of the board of directors. There are no family relationships among any of the directors or executive officers of our general partner.

William R. Moler has been a director of our general partner since February 2015, and served as the Executive Vice President and Chief Operating Officer of our general partner from February 2015 until March 2019, and as President and Chief Operating Officer of our general partner from March 2019 until his appointment as Chief Executive Officer of our general partner effective November 24, 2019. In addition to his service at our general partner, Mr. Moler has served as an executive officer at affiliated companies of TGE since October 2012 and served as a director of TEP GP from February 2013 to June 2018. From 2004 until his departure in October 2012, Mr. Moler served in various capacities with Inergy, L.P. and its affiliates, most recently as Senior Vice President and Chief Operating Officer of Inergy Midstream, L.P. and President and Chief Operating Officer-Natural Gas Midstream Operations of Inergy, L.P. Prior to joining Inergy, L.P., Mr. Moler was with Westport Resources Corporation from 2002 to 2004, where he served as both General Manager of Marketing and Transportation Services and General Manager of Westport Field Services, LLC. Prior to Westport, Mr. Moler served in various leadership positions at Kinder Morgan, Inc. and its predecessors from 1988 to 2002. Mr. Moler has also served on the Board of the National Parkinson's Foundation Heartland Region and served as its President from 2015 to 2017. Mr. Moler earned a Bachelor of Science degree in Mechanical Engineering from Texas Tech University in 1988. We believe that as a result of his background

and knowledge, as well as the attributes of leadership demonstrated by his executive experience, Mr. Moler brings substantial experience and skill to the board of directors of our general partner.

Matthew Sheehy has served as President of our general partner since December 2019. Mr. Sheehy originally joined Tallgrass Energy in November 2012 and served in a number of roles until his departure in March 2018. From November 2016 to March 2018, Mr. Sheehy served as the Senior Vice President and Chief Commercial Officer of TGE GP. In addition, Mr. Sheehy served as the President of Rockies Express Pipeline LLC from December 2013 until July 2017 and as a board member of Rockies Express Pipeline LLC from November 2016 to March 2018. Prior to joining Tallgrass, he served as a Principal and General Partner from August 2008 to November 2012 and as an Associate from August 2005 to August 2008 at Silverhawk Capital Partners LLC. From 2002 to 2005, he served as an Analyst at Wachovia Securities and Wachovia Capital Partners. In addition to his service at our general partner, Mr. Sheehy has served as the Chairman of Bridger Aerospace Group since July 2018 and as the Chairman of Ascent Vision Technologies, LLC since December 2015. Mr. Sheehy earned a Bachelor of Arts degree in Economics from Vanderbilt University in 2002.

Gary J. Brauchle has been Executive Vice President and Chief Financial Officer of our general partner since February 2015. In addition to his service at our general partner, Mr. Brauchle has served as an executive officer at affiliated companies of TGE since November 2012. Prior to joining Tallgrass, Mr. Brauchle was Vice President and Chief Accounting Officer at McDermott International, Inc., a global engineering and construction company serving the oil and gas industry during 2012 and as Corporate Controller from 2010 to 2012. He joined McDermott in 2003 and served in various positions of increasing responsibility, including as Director of Internal Audit from 2005 to 2007 and as Director of Operational Accounting and Assistant Controller for an operating subsidiary from 2007 to 2008 and 2008 to 2010, respectively. Mr. Brauchle also served in the Houston office of PricewaterhouseCoopers' energy and utilities practice from 1997 to 2003, including as a Manager from 2001 to 2003, and with a focus on midstream master limited partnerships, or MLPs. Mr. Brauchle was a postgraduate technical assistant at the Financial Accounting Standards Board (FASB) from 1996 to 1997. Mr. Brauchle is a Certified Public Accountant and a graduate of Texas A&M University, where he received a Master of Science in Accounting in 1996 and a Bachelor of Business Administration in Accounting in 1995.

Christopher R. Jones has been Executive Vice President, General Counsel and Secretary of our general partner since February 2018. In addition to his service at our general partner, Mr. Jones has served as an executive officer of affiliated companies of TGE since May 2016 and has been an attorney with Tallgrass since October 2012. Prior to joining Tallgrass, Mr. Jones was an attorney with the law firm that is now known as Stinson LLP from 2003 to 2012, becoming a partner in 2008. Mr. Jones holds an undergraduate degree and a Juris Doctorate in Law from the University of Kansas.

Gary D. Watkins has served as the Vice President and Chief Accounting Officer of our general partner from February 2015 to March 2019, and as Senior Vice President and Chief Accounting Officer of our general partner since March 2019. Mr. Watkins has been appointed as Executive Vice President and Chief Financial Officer of our general partner effective February 14, 2020 in addition to his current role as Chief Accounting Officer. In addition to his service at our general partner, Mr. Watkins has served as an executive officer of affiliated companies of TGE since April 2014. Previously, Mr. Watkins served as Vice President, Controller and Principal Accounting Officer of DCP Midstream Partners, LP and DCP Midstream, LLC from May 2011 until his departure in April 2014. Mr. Watkins also held the positions of Senior Director-Marketing Accounting and Director of Corporate Accounting with DCP Midstream. Prior to joining DCP Midstream in November 2004, Mr. Watkins held various positions of increasing responsibility at Advanced Energy Industries Inc. Mr. Watkins also served in the Denver offices of Arthur Andersen LLP and KPMG LLP from 1996 through 2002. Mr. Watkins is a Certified Public Accountant and graduate of Colorado State University, where he received a Bachelor of Science in Accounting and a minor in Economics in 1995.

Marcelino Oreja Arburúa has served as a director of our general partner since March 2019. Mr. Arburúa has also served as the Chief Executive Officer and Managing Executive Director of Enagás since September 2012. Between 1992 and 1997, he was General Secretary of the Spanish National Confederation of Young Entrepreneurs. He founded DEF-4 patents and trademarks, which he sold to Garrigues Andersen in 1997, becoming its General Director. Among other senior positions, he was the International Director of Aldeasa, General Director of EMTE and, after the company's merger with COMSA, General Director of COMSA EMTE. He also served as President of FEVE, a Spanish railway company. From 2002 to 2004, he was a Member of the European Parliament. Currently, in addition to his executive positions in Enagás, he is a Trustee of the Thyssen-Bornemisza Collection Foundation and the Transforma España Foundation and was previously a board member of the Basque Energy Agency. He holds a Bachelor's degree in Industrial Engineering from the Higher Technical School of Engineering (ICAI) of the Universidad Pontificia de Comillas and has completed the Global CEO Program and the Advanced Management Program, both from the IESE Business School in Spain. We believe that Mr. Arburúa's education and experience, coupled with the leadership qualities demonstrated by his executive background, bring important experience and skill to the board of directors of our general partner.

Guy G. Buckley has served as a director of our general partner since March 2019 and as a member of the audit committee of our general partner since July 2019. Mr. Buckley has also served as a Senior Advisor at BIP since March 2018. From 1989 to April 2017, Mr. Buckley served in various roles at Spectra Energy Corp and its predecessor companies, most recently as its

Chief Development Officer. Mr. Buckley served as a director of DCP Midstream GP, LLC, the general partner of DCP Midstream, LP, from October 2014 to February 2017. Mr. Buckley has also served on the boards of two non-profits, Avondale House (from 2018 to present) and Theater Under the Stars (from 2016 until 2019). He holds a Master of Business Administration from Boston University and a Bachelor of Engineering in Mechanical Engineering from McGill University. We believe that Mr. Buckley's business and technical experience, and extensive knowledge of the midstream industry, provides important skills to the board of directors of our general partner.

Roy N. Cook has served as a director of our general partner and as a member of the audit committee of our general partner since September 2018. Previously, Mr. Cook served as a director of TEP GP from September 2013 to June 2018 and as a member of the audit committee of TEP GP from December 2017 to June 2018. From 2001 to 2013, Mr. Cook was employed by, and held a variety of roles within, the terminals division of Kinder Morgan, focusing on acquisitions, management, design and operations and specializing in the dry bulk side of the terminals business. Prior to 2001, Mr. Cook owned and managed several businesses in the service industry, including Milwaukee Bulk Terminals, Inc. and Dakota Bulk Terminals, Inc., each of which were sold to Kinder Morgan in 2001. Mr. Cook currently owns several small businesses across diverse industries, including a self-storage business, an electrical service company and a commercial real estate management and development company. He graduated from Kansas State University in 1979 with a B.S. degree in Agriculture Economics. We believe that Mr. Cook's MLP experience, and his intricate knowledge of the terminals business provides valuable strategic and practical insight, and perspective to the board of directors of our general partner.

Thomas A. Gerke has served as a director of our general partner and as a member of the audit committee of our general partner since August 2015. Mr. Gerke has served as the General Counsel and Chief Administrative Officer at H&R Block, a global consumer tax services provider since May 2016 and prior to that starting in January 2012, he served as Chief Legal Officer. In addition, in 2017 while H&R Block went through a CEO transition, Mr. Gerke served as interim President and Chief Executive Officer from August 1, 2017 to October 8, 2017. Prior to joining H&R Block, from January 2011 to April 2011, Mr. Gerke served as Executive Vice President, General Counsel and Secretary of YRC Worldwide, a leading transportation service provider. From July 2009 to December 2010, Mr. Gerke served as Executive Vice Chairman of CenturyLink, a Fortune 500 integrated communications business. From December 2007 to June 2009, he served as President and Chief Executive Officer at Embarq, then a Fortune 500 integrated communications business. He also held the position of Executive Vice President and General Counsel, Law and External Affairs at Embarq from May 2006 to December 2007. From October 1994 through May 2006, Mr. Gerke held several executive and legal positions with Sprint, serving as Executive Vice President and General Counsel for over two years. Mr. Gerke currently serves as a member of the board of directors at Consolidated Communications Holdings, Inc. (NASDAQ: CNSL). He is also a former member of the boards of CenturyLink, Embarq and United States Telecom Association. In addition, he is a former member of the board of trustees for Rockhurst University and the Kansas City Local Investment Commission (LINC). Mr. Gerke earned his Bachelor of Science degree in Business Administration from the University of Missouri in Columbia, his Masters of Business Administration degree from Rockhurst University, and his Juris Doctorate from the University of Missouri School of Law in Kansas City. We believe that Mr. Gerke's leadership roles and board experience at a number of Fortune 500 and other large public companies, as well as his legal acumen and background outside of the energy industry, provides a valuable resource to the board of directors of our general partner.

Wallace C. Henderson, has served as a director of our general partner since March 2019. Mr. Henderson has also served as a Senior Managing Director at Blackstone Infrastructure Partners since January 2018, where he is responsible for leading the group's investment activities in the midstream sector. Prior to joining Blackstone Infrastructure Partners, from May 2011 to December 2017, Mr. Henderson served in various roles at EIG Global Energy Partners, LLC, most recently as the Managing Director, Head of Midstream and member of the Executive Committee where he led the company's global investment activities across all funds and vehicles in midstream energy infrastructure, including transport, processing and liquid natural gas. Prior to joining EIG, Mr. Henderson was a senior financial consultant to Coskata, Inc., an energy technology company from May 2009 until May 2011. Mr. Henderson also spent five years with UBS where he ran the firm's New York-based energy group and led capital raising and advisory assignments for a wide range of energy companies and sponsors including EIG. Prior to his role with UBS, Mr. Henderson served for 18 years as an energy investment banker at Credit Suisse, where he specialized in oil and gas project finance, corporate capital raising and mergers and acquisitions for large U.S. and Latin American oil companies. He served as a director of Southcross Energy Partners GP LLC, the general partner of Southcross Energy Partners, L.P., from August 2014 to November 2017. Mr. Henderson holds a Bachelor's degree in Economics from Kenyon College and a Master of Business Administration degree from Columbia University. We believe that Mr. Henderson's extensive experience with investment in and management of a variety of midstream assets and operations, as well as his capital raising and merger and acquisitions expertise, provides a valuable resource to the board of directors of our general partner.

Matthew J.K. Runkle, has served as a director of our general partner since March 2019. Mr. Runkle has also served as a Managing Director at Blackstone Infrastructure Partners since October 2017. Prior to joining Blackstone Infrastructure Partners, Mr. Runkle served from August 2002 to September 2017 as a Principal at ArcLight Capital Partners, LLC, where he sourced, executed and managed infrastructure investments across the midstream and power sectors. Mr. Runkle also served from July 2000 to July 2002 as an Analyst at the NorthBridge Group, where he provided strategic and management consulting

to utility and energy companies. He holds a Bachelor's degree in Geology and Geophysics from Yale University. We believe that Mr. Runkle's education and significant experience with energy and infrastructure investments bring important skills to the board of directors of our general partner.

Terrance D. Towner has served as a director of our general partner and as a member of the audit committee of our general partner since September 2018. Previously, Mr. Towner served as a director of TEP GP and as a member of the audit committee of TEP GP from August 2013 to June 2018. Mr. Towner currently serves as the Executive Chairman of Jaguar Management Inc. and its affiliates, which makes direct investments in and provides advisory services to various private companies and clients. Mr. Towner is also a director of Base, Inc., Cando Rail Services Holdings, Inc., West Memphis Transload, West Memphis Base Railroad and SilverCreek RCM. Prior to joining Jaguar Management, Inc. in November 2018, Mr. Towner provided business advisory services. Between 2000 and December 2014, Mr. Towner was employed by Watco Companies, a Kansas based transportation company, in various capacities, including Vice Chairman, President, COO and CFO. As President and COO, Mr. Towner was responsible for all operations, safety, quality, human resources, information services and the financial performance of Watco's transportation, mechanical, and terminal and port divisions. Prior to joining Watco, Mr. Towner spent thirteen years in banking including three years as President and CEO of First State Bank & Trust Company of Pittsburg, Kansas. He also served for five years as President of Pitsco, a company that develops and markets computer based education products, and approximately two years as a financial and strategic consultant with Grant Thornton. Following his departure from Grant Thornton, Mr. Towner acquired Joplin.com, an internet service provider located in Joplin, Missouri and subsequently sold the company to Empire District Electric Company, a public utility. Mr. Towner earned his bachelor's degree in Economics from Pittsburg State University in 1981 and his MBA from Pittsburg State University in 1993. We believe that Mr. Towner's business acumen, and a unique perspective on the midstream services industry, helps provide valuable strategic and practical guidance, insight, and perspective to the board of directors of our general partner.

Audit Committee

The board of directors of our general partner has a standing audit committee which is currently comprised of four directors, Guy G. Buckley, Roy N. Cook, Thomas A. Gerke, and Terrance D. Towner. Each audit committee member has past experience in accounting or related financial management experience. The board has determined that all our audit committee members are independent under Section 303A.02 of the NYSE listing standards and Rule 10A-3 of the Exchange Act. In making the independence determination, the board considered the requirements of the NYSE, the SEC and our Code of Business Conduct and Ethics. Among other factors, the board considered current or previous employment with us, our auditors or their affiliates by the director or his immediate family members, ownership of our voting securities and other material relationships with us. The audit committee has adopted a charter, which has been ratified and approved by the board of directors.

Terrance D. Towner has been designated by the board as the audit committee's financial expert meeting the requirements promulgated by the SEC and set forth in Item 407(d) of Regulation S-K of the Exchange Act, based upon his education and employment experience as more fully detailed in Mr. Towner's biography set forth above. Roy N. Cook acts as the Chairman of our audit committee.

A copy of the Audit Committee Charter is available to any person, free of charge, at our website at www.tallgrassenergy.com.

Conflicts Committee

Our general partner may, from time to time, have a conflicts committee to which the board of directors will appoint at least two independent directors and which may be asked to review specific matters that the board believes may involve conflicts of interest between us and our general partner or the owners of our general partner. The conflicts committee will determine if the resolution of any conflict of interest referred to it by our general partner is in the best interests of our partnership. There is no requirement that our general partner seek the approval of the conflicts committee for the resolution of any conflict. The members of the conflicts committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates, may not hold an ownership interest in the general partner or its affiliates other than shares or awards under any long-term incentive plan, equity compensation plan or similar plan implemented by the general partner or us, and must meet the independence and experience standards established by the NYSE and the Exchange Act to serve on an audit committee of a board of directors.

Any matters approved by the conflicts committee will be conclusively deemed to have been approved by all of our partners, and shall not constitute a breach by our general partner of any duties it may owe us or our shareholders. Any shareholder challenging any matter approved by the conflicts committee will have the burden of proving that the members of the conflicts committee did not subjectively believe that the matter was in the best interests of our partnership. Moreover, any acts taken or omitted to be taken in reliance upon the advice or opinions of experts such as legal counsel, accountants, appraisers, management consultants and investment bankers, where our general partner (or any members of the board of directors of our general partner including any member of the conflicts committee) reasonably believes the advice or opinion to

be within such person's professional or expert competence, shall be conclusively presumed to have been done or omitted in good faith.

Corporate Governance Guidelines and Code of Business Conduct and Ethics

Our general partner has adopted Corporate Governance Guidelines and a Code of Business Conduct and Ethics applicable to all of our employees, officers and directors with regard to Partnership-related activities. The Corporate Governance Guidelines and the Code of Business Conduct and Ethics each incorporate guidelines designed to deter wrongdoing and to promote honest and ethical conduct and compliance with applicable laws and regulations. They also incorporate expectations of our employees that enable us to provide accurate and timely disclosure in our filings with the SEC and other public communications. A copy of the Corporate Governance Guidelines and the Code of Business Conduct and Ethics are available to any person, free of charge, at our website at www.tallgrassenergy.com.

The Chairman of the audit committee of our general partner, currently Roy N. Cook, presides over any executive session of the board of directors of our general partner in which the members of our management are not present. Interested parties may communicate directly with the independent members of the board of directors of our general partner by submitting in an envelope marked "Confidential" addressed to the "Independent Members of the Board" in care of the Secretary of the General Partner at: Tallgrass Energy, LP, 4200 W. 115th Street, Suite 350, Leawood, Kansas 66211.

Item 11. Executive Compensation

Compensation Discussion and Analysis

Executive Summary and Background

We and our general partner were formed in Delaware in February 2015. Our general partner did not accrue any obligations with respect to management incentive or retirement benefits for its directors and executive officers until after our initial public offering in May 2015. Our business is managed and operated by the directors and executive officers of our general partner. All employees, including our Named Executive Officers (as defined in "*Summary Compensation Table*" below), are employed by Tallgrass Management. Because Tallgrass Management is a wholly-owned subsidiary of Tallgrass Equity, the costs of employer and director compensation and benefits are incurred directly by Tallgrass Equity.

Prior to July 1, 2018, Tallgrass Management was a wholly-owned subsidiary of Tallgrass Energy Holdings and Tallgrass Equity reimbursed Tallgrass Energy Holdings and its affiliates for all salaries, benefits and other compensation expenses for employees of Tallgrass Management (including the Named Executive Officers) to the extent such employees provided services to us pursuant to an allocation agreed upon between our general partner and Tallgrass Energy Holdings under the terms of the TGE Omnibus Agreement. The TGE Omnibus Agreement was terminated effective March 11, 2019 in connection with the closing of the March 2019 Blackstone Acquisition.

Compensation of our Named Executive Officers is set and approved by the board of directors of our general partner. In addition, each of our Named Executive Officers have entered into employment agreements which were approved by the board of directors of our general partner.

Philosophy and Objectives

Since our initial public offering in May 2015, we have employed a compensation philosophy that emphasizes pay for performance and places the majority of each Named Executive Officer's compensation at risk. We believe our pay-for-performance approach aligns the interests of our Named Executive Officers with that of our Class A shareholders, and at the same time enables us to maintain a lower level of recurring compensation costs in the event our operating or financial performance is below expectations. We design our executive compensation to attract and retain individuals with the background and skills necessary to successfully execute our business model in a demanding environment, to motivate those individuals to reach near-term and long-term goals in a way that aligns their interest with that of our Class A shareholders, and to reward success in reaching such goals.

We use three primary elements of compensation to fulfill that design: salary, bonuses and long-term equity incentive awards. Bonuses and long-term equity incentives (as opposed to salary) generally represent the performance driven elements. These two elements are also flexible in application and can be tailored to meet our objectives. The determination of specific individuals' bonuses is based on their relative contribution to achieving or exceeding relative near-term company goals and the determination of specific individuals' long-term incentive equity awards is based on their actual and anticipated contribution to longer term performance objectives. The primary long-term measure of our performance is our ability to maintain or increase cash available for dividends while maintaining safe operations and long-term stable cash flow and financial health.

We do not maintain a defined benefit or pension plan for our Named Executive Officers as we believe such plans primarily reward longevity and not performance. We provide a basic benefits package generally to all employees, which includes a 401(k) plan and health, disability and life insurance.

Elements of Compensation

Salary. Each of the employment agreements with our Named Executive Officers establishes an annualized base salary. We benchmark our salary amounts to comparable companies in our industry. We believe our salaries are generally competitive with the universe of similarly situated midstream energy companies, but are moderate relative to energy industry competitors for people with similar roles and responsibilities.

Bonuses. Each of the employment agreements with our Named Executive Officers establishes a minimum targeted annual cash bonus and any bonuses in excess of the minimum are discretionary bonuses. Generally, our bonuses to Named Executive Officers have consisted of a cash bonus. In 2018, Messrs. Brauchle, Moler and Jones were granted awards under the Legacy LTIP (as defined below) as an additional component of their 2018 bonus. These awards were granted on January 31, 2019 and vested immediately. The recipients of these awards were issued the Class A shares on February 7, 2020 net of the Class A shares withheld to satisfy the tax withholding obligations related to the vesting of such awards.

Awards under Long-Term Incentive Plans. We have two long-term incentive plans. The Tallgrass Energy GP, LLC Long-Term Incentive Plan (f/k/a the TEGP Management, LLC Long-Term Incentive Plan), was originally adopted by our general partner effective as of May 1, 2015, and was amended and restated effective August 2, 2018 (as amended, the "TGE LTIP"). In addition, the Tallgrass MLP GP, LLC Long-Term Incentive Plan was originally adopted by TEP GP effective as of May 13, 2013, and was amended and restated effective August 2, 2018 (as amended, the "Legacy LTIP" and together with the TGE LTIP, the "Plans"). In connection with the completion of the TEP Merger effective June 30, 2018, discussed in Note 1 –

Description of Business, the Legacy LTIP was assumed by our general partner and TEP's outstanding equity participation units were converted to equity participation shares at a ratio of 2.0 equity participation shares for each outstanding TEP equity participation unit.

Awards under the Plans may consist of, among others, unrestricted shares, restricted shares, equity participation shares, options and share appreciation rights which may be granted to (i) the employees of our general partner and its affiliates who perform services for us, (ii) the non-employee directors of our general partner and (iii) the consultants who perform services for us (such awards, the "LTIP Awards"). Historically, we have used equity participation share awards under the Plans to encourage and reward timely achievement of certain events or dividend levels and align the long-term interests of our Named Executive Officers with those of our Class A shareholders. An equity participation share is the right to receive, upon the satisfaction of vesting criteria specified in the grant, a Class A share. Equity participation share awards under the Plans have historically been the primary long-term equity incentive provided to our Named Executive Officers and appropriately incentivizes our Named Executive Officers to seek stable growth of the business aligned with our shareholders.

Vesting Conditions. The vesting conditions applicable to the equity participation shares held by Named Executive Officers that are outstanding under the Plans can generally be divided into the following categories:

- The first category of awards was granted by TGE in October 2018 (the "2018 Grants") and will vest on the earliest date on or after November 1, 2022, on which the average compounded annual distribution growth rate, based upon the regular quarterly distribution paid by TGE on, or immediately prior to, such date is at least 5% over an annualized distribution rate of \$1.99 per Class A share, as determined by the board of directors of our general partner (the "Distribution Hurdle Date") as long as such Named Executive Officer remains continuously employed by us through the vesting date. If the Distribution Hurdle Date has not occurred by October 19, 2025, such equity participation shares will expire and terminate and no vesting will occur. Following consummation of the Take-Private Merger, the outstanding awards in this category will vest on November 1, 2022 without regard to whether the Distribution Hurdle Date has occurred. Mr. Watkins is the only Named Executive Officer that has any outstanding granted equity participation shares in this category. See *"Potential Payments upon Termination or Change-in-Control"* for a description of the conditions that would accelerate vesting of the 2018 Grants.
- The second category of awards was granted by TGE in March 2019 (the "2019 Grants") and will vest on the dates and in the percentages set forth in the applicable award agreement as long as such Named Executive Officer remains continuously employed by us through the vesting date. Messrs. Moler, Brauchle, Jones, and Watkins were granted equity participation shares in this category. Mr. Moler's equity participation shares will vest one-half on October 31, 2022 and the remaining one-half on October 31, 2023. Mr. Brauchle's equity participation shares will vest in full on December 31, 2020. Messrs. Jones' and Watkins' equity participation shares will vest one-half on October 31, 2023 and the remaining one-half on October 31, 2024.

Agreements to Grant Awards. Each of the employment agreements with Messrs. Moler and Sheehy provides that in the event the Take-Private Merger is not completed prior to April 30, 2020, on May 1, 2020 Messrs. Moler and Sheehy will be eligible to receive performance awards (the "Performance Awards") as further described below.

Mr. Moler will receive 18,132,145 Performance Awards as follows:

- 10,623,673 Performance Awards with a per Performance Award value equal to (i) the lower of (a) the volume-weighted average price of a Class A share over the 60-day period beginning November 1, 2024 and (b) \$36.04/share, with such price to be reduced based on the future value of any dividends paid between January 1, 2020 and December 31, 2024, assuming a 10.5% rate of return, minus (ii) a per share price of \$32.95/share, with such price to be reduced based on the future value of any dividends paid between January 1, 2020 and December 31, 2024, assuming a 10.5% rate of return;
- 4,756,377 Performance Awards with a per Performance Award value equal to (i) the lower of (a) the volume-weighted average price of a Class A share over the 60-day period beginning November 1, 2024 and (b) \$40.23/share, with such price to be reduced based on the future value of any dividends paid between January 1, 2020 and December 31, 2024, assuming a 12.5% rate of return, minus (ii) a per share price of \$36.04/share, with such price to be reduced based on the future value of any dividends paid between January 1, 2020 and December 31, 2024, assuming a 12.5% rate of return; and
- 2,752,095 Performance Awards with a per Performance Award value equal to (i) the lower of (a) the volume-weighted average price of a Class A share over the 60-day period beginning November 1, 2024 and (b) \$44.79/share, with such price to be reduced based on the future value of any dividends paid between January 1, 2020 and December 31, 2024, assuming a 15.0% rate of return, minus (ii) a per share price of \$40.23/share, with such price to be reduced based on the future value of any dividends paid between January 1, 2020 and December 31, 2024, assuming a 15.0% rate of return.

The Performance Awards that Mr. Moler is eligible to receive vested one-sixth on November 24, 2019 and will vest one-sixth on December 31st of each of 2020, 2021, 2022, 2023 and 2024, subject to his continued employment through the applicable vesting dates. If granted, the foregoing Performance Awards, to the extent vested, will be settled in Class A shares, less applicable withholdings, on January 10, 2025 based on the closing price of the Class A shares on the date that is two trading days prior to January 10, 2025; provided, however, that a maximum of 2,700,000 Class A shares may be issued pursuant to the settlement of such Performance Awards with any remaining value to be settled in cash.

Mr. Sheehy is eligible to receive 12,088,097 Performance Awards as follows:

- 7,082,449 Performance Awards with a per Performance Award value equal to (i) the lower of (a) the volume-weighted average price of a Class A share over the 60-day period beginning November 1, 2024 and (b) \$36.04/share, with such price to be reduced based on the future value of any dividends paid between January 1, 2020 and December 31, 2024, assuming a 10.5% rate of return, minus (ii) a per share price of \$32.95/share, with such price to be reduced based on the future value of any dividends paid between January 1, 2020 and December 31, 2024, assuming a 10.5% rate of return;
- 3,170,918 Performance Awards with a per Performance Award value equal to (i) the lower of (a) the volume-weighted average price of a Class A share over the 60-day period beginning November 1, 2024 and (b) \$40.23/share, with such price to be reduced based on the future value of any dividends paid between January 1, 2020 and December 31, 2024, assuming a 12.5% rate of return, minus (ii) a per share price of \$36.04/share, with such price to be reduced based on the future value of any dividends paid between January 1, 2020 and December 31, 2024, assuming a 12.5% rate of return; and
- 1,834,730 Performance Awards with a per Performance Award value equal to (i) the lower of (a) the volume-weighted average price of a Class A share over the 60-day period beginning November 1, 2024 and (b) \$44.79/share, with such price to be reduced based on the future value of any dividends paid between January 1, 2020 and December 31, 2024, assuming a 15.0% rate of return, minus (ii) a per share price of \$40.23/share, with such price to be reduced based on the future value of any dividends paid between January 1, 2020 and December 31, 2024, assuming a 15.0% rate of return.

The Performance Awards that Mr. Sheehy is eligible to receive vested one-sixth on December 3, 2019 and will vest one-sixth on December 31st of each of 2020, 2021, 2022, 2023 and 2024, subject to his continued employment through the applicable vesting dates. If granted, the foregoing Performance Awards, to the extent vested, will be settled in Class A shares, less applicable withholdings, on January 10, 2025 based on the closing price of Class A shares on the date that is two trading days prior to January 10, 2025; provided, however, that a maximum of 1,800,000 Class A shares may be issued pursuant to the settlement of such Performance Awards with any remaining value to be settled in cash.

In the event the Take-Private Merger is completed prior to April 30, 2020, Messrs. Moler and Sheehy will be eligible to receive, in lieu of the Performance Awards, awards that are the economic equivalent of the Performance Awards (the

"Replacement Awards"). If granted, the Replacement Awards, to the extent vested, would be settled in cash no later than June 30, 2025.

The board of directors of our general partner retained Korn Ferry in November 2019 to advise it regarding certain matters, including the design and implementation of compensation structures for Mr. Sheehy and Mr. Moler, to assess market data, historical compensation, data regarding compensation paid by market peers and competitors for human talent and other relevant information, and to evaluate whether the our proposed compensation structures for Mr. Sheehy and Mr. Moler fulfill their purpose of retaining and incentivizing Mr. Sheehy and Mr. Moler to perform at a high level to meet our operational and strategic objectives. The board of directors of our general partner received a presentation and recommendations from Korn Ferry regarding the results of its compensation analysis, discussed and considered such presentation and recommendations and determined that it was appropriate to adopt the compensation structures for Mr. Sheehy and Mr. Moler reflected in their respective employment agreements, including the Performance Awards described above.

Relation of Compensation Elements to Compensation Objectives

Our compensation program is designed to motivate, reward and retain our Named Executive Officers. Bonuses serve as a near-term motivation and reward for achieving positive short-term results, such as meeting specified dividend growth and other financial guidance targets. Longer-term retention is facilitated by the requirement for continued employment or service for specified time periods in order for LTIP Awards to fully vest. The level of bonuses and LTIP Awards in relation to salaries of our Named Executive Officers exemplifies the weighting towards performance based, at-risk compensation.

We strive to focus on performance-based compensation elements in an attempt to create a performance-driven environment in which our Named Executive Officers are (i) motivated to perform over both the short-term and the long-term, (ii) appropriately rewarded for their services and (iii) encouraged to remain with us even after meeting long-term performance goals. We believe our compensation philosophy as implemented by application of the three primary compensation elements (i) aligns the interests of our Named Executive Officers with our Class A shareholders, (ii) positions us to achieve our business goals, and (iii) effectively encourages the exercise of sound judgment and risk-taking that is conducive to creating and sustaining long-term value. We believe the processes we employ to apply the elements of compensation (as discussed in more detail below) provide an adequate level of oversight with respect to the degree of risk being taken by management to achieve short-term and long-term performance goals. See *"Relation of Compensation Policies and Practices to Risk Management."*

We believe our compensation program has been instrumental in our achievement of stated objectives. One of the primary measures of our performance is our ability to enhance the ability of our assets to generate cash available for dividends that we can use to increase quarterly dividends to our Class A shareholders. In the period since our initial public offering through the dividend paid for the third quarter of 2019, which was the last dividend prior to entering into the Take-Private Merger Agreement, our compounded annual dividend growth rate was 40%. This dividend growth has, in part, supported our decision to pay bonuses to our Named Executive Officers related to that period.

Application of Compensation Elements

Salary. Each of the employment agreements with our Named Executive Officers establishes an annualized base salary. We do not make systematic annual adjustments to the salaries of our Named Executive Officers. We do, however, make salary adjustments as necessary to ensure that our salaries remain competitive in the industry marketplace.

Bonuses. Each of the employment agreements with our Named Executive Officers establishes a minimum targeted annual cash bonus and any bonuses in excess of the minimum are discretionary bonuses. These discretionary bonuses are determined based on our performance relative to our annual budget, our dividend growth targets, and other quantitative and qualitative goals established each year. Such annual objectives are discussed and reviewed with the board of directors periodically during the year and then again in conjunction with the review and authorization of the annual budget and this annual report.

At the end of each year, the Chief Executive Officer, with assistance from other members of executive management, performs a quantitative and qualitative assessment of our performance relative to our goals. Key quantitative measures include Adjusted EBITDA, cash available for dividend, dividend coverage, and growth in the annualized quarterly dividend level per Class A share relative to annual growth targets. We also compare our market performance relative to our peers and major indices. Our primary performance metric is our ability to generate increasing and sustainable cash available for dividends. Accordingly, although net income and net income per unit are monitored to highlight inconsistencies with our primary performance metrics, we do not consider net income and net income per unit to be key performance measures. Executive management's analysis of our performance examines our accomplishments, shortfalls and overall performance against opportunity, taking into account controllable and non-controllable factors encountered during the year.

After the annual company-level performance analysis is completed, our Chief Executive Officer and other members of executive management, along with personnel from our human resources department, consider bonuses and salary adjustments for our employees, including our Named Executive Officers. There are no set formulas for determining salary adjustments or annual discretionary bonuses for our Named Executive Officers. Factors considered by executive management in determining the level of salary adjustment and bonus in general include (i) whether or not we achieved any goals established for the year and any notable shortfalls relative to expectations; (ii) the level of difficulty associated with achieving any such objectives based on the opportunities and challenges encountered during the year; (iii) current year operating and financial performance relative to both public guidance and prior year's performance; (iv) significant transactions or accomplishments for the period not included in the goals for the year; (v) our prospects at the end of the year with respect to future growth and performance; and (vi) our contractual requirements under all employment agreements with our employees, including our Named Executive Officers. The Chief Executive Officer and other members of executive management take these factors into consideration, as well as the relative contributions of each of our Named Executive Officers to the year's performance, in developing recommendations for Named Executive Officer bonus amounts and salary adjustments.

These recommendations for discretionary bonus amounts and salary adjustments for our Named Executive Officers are presented to the board of directors of our general partner, adjusted as appropriate, and then formally approved by the board of directors.

Long-Term Incentive Awards. We do not make systematic annual grants of LTIP Awards to our Named Executive Officers. We have historically attempted to time the granting of LTIP Awards such that the creation of new long-term incentives coincides with the satisfaction of vesting criteria under existing awards. We have not formally decided on a recurring grant cycle for future grants, but we intend for future grants to provide a balance between a meaningful retention period for us and a visible, reasonable, growth-oriented reward for the Named Executive Officer. Under existing LTIP Awards, achievement of performance targets does not shorten the minimum service period requirement.

Application in 2019

At the beginning of 2019, we established the following financial performance objectives for 2019:

- Adjusted EBITDA of \$965 million - \$1.035 billion for the year ended December 31, 2019;
- Cash Available for Dividends of \$760 - \$835 million for the year ended December 31, 2019;
- Dividend coverage of greater than 1.25x for the year ended December 31, 2019; and
- Dividend growth of approximately 6 - 8% for TGE.

We met or exceeded all these goals:

- Our Adjusted EBITDA for the year ended December 31, 2019 was approximately \$996.3 million;
- Our Cash Available for Dividends for the year ended December 31, 2019 was approximately \$798.2 million;
- Our dividend coverage for the nine months ended September 30, 2019 was approximately 1.35x, which was the last period prior to entering into the Take-Private Merger Agreement; and
- Our dividends on Class A shares in the third quarter of 2019, our last dividend prior to entering into the Take-Private Merger Agreement, represented a 7.8% increase from the third quarter of 2018.

Additionally, our internal qualitative goals included (a) advancing multi-year programs and initiatives and preparing the organization for future growth, and (b) continuing to promote a culture of safety and environmental responsibility throughout the organization. We achieved several accomplishments with respect to these qualitative goals, including:

- The completion of the Iron Horse Pipeline project, Guernsey Terminal facilities, and Pony Express expansion projects;
- The receipt of the FERC approval to the applications pursuant to section 7(c) of the NGA for the Cheyenne Connector Pipeline and the Cheyenne Hub Enhancement Project;
- The pre-filing settlement with respect to TIGT rate case and the settlement in principle with respect to the Trailblazer Pipeline rate case;
- Third-party acquisitions in 2019, including the acquisition of CES in May 2019;
- The extension of the Rockies Express revolving credit facility in November 2019; and

- The senior note offerings by Rockies Express in April 2019 of \$550 million in aggregate principal amount of 4.95% senior notes due 2029 and in January 2020 of \$750 million in aggregate principal amount composed of two tranches, \$400 million of 3.60% senior notes due 2025 and \$350 million of 4.80% senior notes due 2030.

For 2019, the elements of compensation were applied as described below.

Salary. In 2019, we did not implement a material salary increase for Mr. Watkins. In connection with entering into the employment agreements discussed in "*Employment Agreements*" below, Mr. Moler received a salary increase of 150% and Messrs. Brauchle and Jones received salary increases of approximately 67% and 68% over 2018.

Bonuses. Based on the Chief Executive Officer's annual performance review and the individual performance of each of our Named Executive Officers, the board of directors of our general partner approved the annual bonuses for our Named Executive Officers reflected in the Summary Compensation Table and notes thereto. Such amounts take into account performance relative to our 2019 goals; the level of difficulty associated with achieving such objectives; our relative positioning at the end of the year with respect to future growth and performance; and the significant transactions or accomplishments for the period not included in the goals for the year. The board of directors of our general partner also considered, on a subjective basis, how well the executive officer performed his or her duties during the year.

Long-Term Incentive Awards. Each of our Named Executive Officers, with the exception of Messrs. Sheehy and Dehaemers, received grants under the Plans in 2019. As noted below, we believe the substantial equity interests held by our management team, including our Named Executive Officers, in TGE and Tallgrass Equity aligns their interests with those of our Class A shareholders, and is taken into account when considering the level of equity incentives granted to our Named Executive Officers under our compensation programs.

Other Compensation Related Matters

Equity Ownership. Although we encourage our Named Executive Officers to acquire and retain ownership in Class A shares, we do not require our Named Executive Officers to maintain a specified equity ownership level. Our policies, including our Insider Trading Policy, strongly discourage our Named Executive Officers from using puts, calls or options to hedge the economic risk of their ownership in TGE. Based on the closing price of Class A shares on February 10, 2020, the value of the combined equity ownership of our Named Executive Officers discussed below was significantly greater than their combined aggregate salaries and bonuses for 2019. We believe that the substantial equity interests held by our management team in TGE and Tallgrass Equity further aligns their interests with those of our Class A shareholders, and is taken into account when considering the level of equity incentives granted to our Named Executive Officers under our compensation programs.

Equity Ownership in TGE. Other than Mr. Sheehy, each of our Named Executive Officers beneficially own Class A shares in TGE and some of our Named Executive Officers own Class B shares (together with an equal number of TE Units). As of February 10, 2020, our Named Executive Officers beneficially owned, in the aggregate, 3,900,871 Class A shares (excluding any unvested LTIP Awards) and 649,892 Class B shares (together with an equal number of TE Units), representing an approximate 1.62% economic interest in us.

Recovery of Prior Awards. Except as provided by applicable laws and regulations and as set forth below, we do not have a policy with respect to adjustment or recovery of awards or payments if relevant company performance measures upon which previous awards were based are restated or otherwise adjusted in a manner that would have reduced the size of such award or payment if previously known.

Each of the employment agreements with Messrs. Moler and Sheehy provides that the board of directors of our general partner has the right, in its sole discretion and to the extent permitted by law, to require reimbursement or forfeiture (or "clawback") of certain incentive compensation in the event of a restatement of our financial statements due to material non-compliance with any financial reporting requirement under applicable securities laws.

Section 162(m). With respect to the deduction limitations under Section 162(m) of the Code, we are a limited partnership and do not fall within the definition of a "corporation" under Section 162(m).

Change-in-Control Triggers and Termination Payments. The 2018 Grants and the 2019 Grants include accelerated vesting if either (i) both (A) a qualifying transaction occurs, and (B) in connection with or within 12 months following such qualifying transaction, Mr. Dehaemers, Mr. Moler, Mr. Brauchle or Mr. Jones (excluding the name of the award recipient in such recipient's award agreement) cease to comprise at least one of the specified executive officer roles of our general partner or its affiliates, or (ii) (A) Mr. Dehaemers, Mr. Moler, Mr. Brauchle or Mr. Jones (excluding the name of the award recipient in such recipient's award agreement) cease to comprise at least one of the specified executive officer roles of our general partner or of its affiliates, and (B) within 2 years after the occurrence of such event, the award recipient is terminated without cause. The March 2019 Blackstone Acquisition constitutes a qualifying transaction under the 2018 Grants.

The provision of equity acceleration for defined events help to create a retention tool by assuring the executive that the benefit of the compensation arrangement will be at least partially realized despite the occurrence of an event that could materially alter the executive's employment arrangement.

In addition, each of the employment agreements with Messrs. Moler, Sheehy, Brauchle, Jones and Watkins provides for severance in the event his employment is terminated without "cause" or in the event he resigns for "good reason." See *"Potential Payments upon Termination or Change-in-Control."*

Relation of Compensation Policies and Practices to Risk Management

Our compensation policies and practices are designed to provide rewards for short-term and long-term performance, both on an individual basis and at the entity level. In general, optimal financial and operational performance, particularly in a competitive business like ours, requires some degree of risk-taking. Accordingly, the use of compensation as an incentive for performance could potentially cause management and others to take unnecessary or excessive risks to reach the performance thresholds. For us, such risks would primarily attach to the execution and financing of capital expansion projects and asset acquisitions and the realization of associated returns from both, as well as to certain commercial activities conducted in our operational segments, in order to achieve the dividend growth performance hurdles.

From a risk management perspective, we monitor and structure our commercial activities in a manner intended to control and minimize the potential for unwarranted risk-taking. See Note 9 – *Risk Management*. We also monitor and measure our capital projects and acquisitions relative to expectations. In general, we believe our compensation arrangements serve to minimize the incentive for unwarranted risk-taking to achieve short-term, unsustainable results. See *"Compensation Discussion and Analysis – Relation of Compensation Elements to Compensation Objectives."*

In combination with our risk-management practices, we do not believe that risks arising from our compensation policies and practices for our employees are reasonably likely to have a material adverse effect on us.

Summary Compensation Table

The following table reflects the total compensation of the principal executive officer, the principal financial officer and the three other most highly compensated executive officers of our general partner for 2019 (the "Named Executive Officers") for services rendered to all Tallgrass-related entities, including TEP, TGE, Tallgrass Management and Tallgrass Development, for the fiscal years ending December 31, 2019, 2018, and 2017.

	Year	Salary ⁽¹⁾	Cash Bonus ⁽²⁾	Equity Awards ⁽³⁾	All Other Compensation ⁽⁴⁾	Total
William R. Moler	2019	\$ 437,500	\$1,500,000	\$ 4,585,543	\$ 29,296	\$ 6,552,339
Chief Executive Officer	2018	\$ 300,000	\$ 500,000	\$ 951,328	\$ 28,652	\$ 1,779,980
and Director; Former President and Chief Operating Officer	2017	\$ 300,000	\$ 400,943	\$ —	\$ 28,152	\$ 729,095
David G. Dehaemers, Jr.	2019	\$ 453,846	\$1,000,000	\$ —	\$ 29,296	\$ 1,483,142
Former President, Chief Executive Officer and Director	2018	\$ 300,000	\$1,000,000	\$ —	\$ 28,652	\$ 1,328,652
	2017	\$ 300,000	\$1,000,739	\$ —	\$ 28,152	\$ 1,328,891
Matthew Sheehy	2019	\$ 17,308	\$ —	\$ —	\$ 1,839	\$ 19,147
President						
Gary J. Brauchle	2019	\$ 453,846	\$1,500,000	\$ 2,477,293	\$ 29,285	\$ 4,460,424
Executive Vice President and Chief Financial Officer	2018	\$ 300,000	\$ 500,000	\$ 710,854	\$ 28,459	\$ 1,539,313
	2017	\$ 299,712	\$ 750,942	\$ —	\$ 27,955	\$ 1,078,609
Christopher R. Jones	2019	\$ 453,846	\$1,500,000	\$ 5,873,693	\$ 29,296	\$ 7,856,835
Executive Vice President, General Counsel and Secretary	2018	\$ 297,116	\$ 500,000	\$ 3,821,254	\$ 28,644	\$ 4,647,014
	2017	\$ 271,569	\$ 750,942	\$ 3,545,100	\$ 27,686	\$ 4,595,297
Gary D. Watkins	2019	\$ 250,000	\$ 375,000	\$ 2,237,250	\$ 26,080	\$ 2,888,330
Senior Vice President and Chief Accounting Officer	2018	\$ 247,116	\$ 250,000	\$ 1,209,600	\$ 25,664	\$ 1,732,380
	2017	\$ 224,922	\$ 248,435	\$ 1,378,650	\$ 23,356	\$ 1,875,363

(1) Reflects actual salary received. Salary adjustments are typically implemented during February, which results in odd amounts actually received by the indicated Named Executive Officer.

(2) Represents discretionary cash bonuses paid in 2020, 2019 and 2018 based on performance in 2019, 2018 and 2017, respectively, as well as a bonus of \$500 after tax that was paid to all employees in 2017.

(3) The amounts in this column include equity participation shares granted pursuant to the Plans. Each of our Named Executive Officers, with the exception of Mr. Dehaemers and Mr. Sheehy, received grants under the Plans in 2019 and 2018. In addition, Mr. Moler, Mr. Brauchle, and Mr. Jones each received grants in January 2019 as a component of their 2018 bonuses. Mr. Jones and Mr. Watkins were the only Named Executive Officers to receive grants under the Plans during 2017. These amounts represent the aggregate grant date fair value determined in accordance with ASC Topic 718 for equity participation units, or EPU's, granted under the Legacy LTIP prior to June 30, 2018 and equity participation shares, or EPS's granted under the Plans. Pursuant to SEC rules, the amounts shown in the Summary Compensation Table for awards subject to performance conditions are based on the probable outcome as of the date of grant and exclude the impact of estimated forfeitures. The EPU's and EPS's are non-participating, therefore the grant date fair value is discounted from the grant date fair value of TEP's common units or TGE's Class A shares, as appropriate, for the present value of the expected (but non-participating) future dividends during the vesting period. For additional information, see Note 17 – *Equity-Based Compensation*. These amounts do not correspond to the actual value that will be recognized by the executive.

- (4) The amounts in the column include the following: contributions under the 401(k) savings plan (includes \$28,000 for Mr. Moler, \$28,000 for Mr. Dehaemers, \$1,731 for Mr. Sheehy, \$27,989 for Mr. Brauchle, \$28,000 for Mr. Jones, and \$25,000 for Mr. Watkins for the year ended December 31, 2019; \$27,500 for Mr. Moler, \$27,500 for Mr. Dehaemers, \$27,307 for Mr. Brauchle, \$27,500 for Mr. Jones, and \$24,712 for Mr. Watkins for the year ended December 31, 2018; and \$27,000 for Mr. Moler, \$27,000 for Mr. Dehaemers, \$26,804 for Mr. Brauchle, \$26,640 for Mr. Jones, and \$22,492 for Mr. Watkins for the year ended December 31, 2017) and the dollar value of premiums paid for group life, accidental death and dismemberment insurance.

CEO Pay Ratio

As required by Section 953(b) of the Dodd-Frank Act and Item 402(u) of Regulation S-K, we are providing information regarding the internal pay ratio between the annual total compensation of our Chief Executive Officer and the median of the annual total compensation of all employees. To determine the median of the annual total compensation of all such employees, excluding our Chief Executive Officer, we identified the "median employee" by comparing the amount of salary, wages and tips of such employees, whether full-time, part-time, seasonal or temporary, as reflected in the payroll records of Tallgrass Management for the period from January 1, 2019 through December 31, 2019.

Our Chief Executive Officer as of December 31, 2019, Mr. Moler, was appointed in this role effective November 24, 2019. Because Mr. Moler served as one of our Named Executive Officers before this appointment, his compensation reflected in the Summary Compensation Table above includes amounts attributable to his prior position. Accordingly, for purposes of calculation of the internal pay ratio pursuant to Item 402(u) of Regulation S-K, we annualized Mr. Moler's salary as Chief Executive Officer by using his base salary of \$750,000 he receives pursuant to the employment agreement entered into effective November 24, 2019 in connection with his appointment as Chief Executive Officer. We then added the 2019 cash bonus of \$1,500,000 received by Mr. Moler as Chief Executive Officer pursuant to his employment agreement, as disclosed in the Summary Compensation Table above. Finally, we added the amount of \$29,296 disclosed with respect to Mr. Moler in the Summary Compensation Table above under All Other Compensation, as this compensation was not modified as a result of Mr. Moler's appointment as Chief Executive Officer and therefore represents an annualized amount for Mr. Moler in his role as Chief Executive Officer.

Based on the foregoing, we determined that the annual total compensation of our Chief Executive Officer for the year ended December 31, 2019 was \$2,279,296. The median of the annual total compensation of all employees, excluding our Chief Executive Officer, was \$106,934. Therefore, our Chief Executive Officer's annual total compensation is 21.3 times that of the median of the annual total compensation of all employees of Tallgrass Management.

Grants of Plan-Based Awards Table

The following table provides information concerning each grant of an award made to a Named Executive Officer during 2019 under the Plans.

	Grant Type	Grant Date	Number of Shares or Units	Grant Date Fair Value of Awards ⁽¹⁾
William R. Moler				
<i>Chief Executive Officer and</i>	TGE Equity Participation Shares	1/31/19	23,250 ⁽²⁾	\$ 21.69
<i>Director; Former President and</i>		3/12/19	250,000 ⁽³⁾	\$ 16.33
<i>Chief Operating Officer</i>				
Gary J. Brauchle				
<i>Executive Vice President and</i>	TGE Equity Participation Shares	1/31/19	23,250 ⁽²⁾	\$ 21.69
<i>Chief Financial Officer</i>		3/12/19	100,000 ⁽⁴⁾	\$ 19.73
Christopher R. Jones				
<i>Executive Vice President, General</i>	TGE Equity Participation Shares	1/31/19	23,250 ⁽²⁾	\$ 21.69
<i>Counsel and Secretary</i>		3/12/19	360,000 ⁽⁵⁾	\$ 14.92
Gary D. Watkins				
<i>Senior Vice President and</i>	TGE Equity Participation Shares	3/12/19	150,000 ⁽⁵⁾	\$ 14.92
<i>Chief Accounting Officer</i>				

- (1) The amounts in this column represent the aggregate grant date fair value determined in accordance with ASC Topic 718 for equity participation shares, or EPSs, granted under the Plans. Pursuant to SEC rules, the amounts shown in this table for awards subject to performance conditions, if applicable, are based on the probable outcome as of the date of grant and exclude the impact of estimated forfeitures. The EPSs are non-participating, therefore the grant date fair value is discounted from the grant date fair value of TGE's Class A shares for the present value of the expected (but non-participating) future dividends during the vesting period. For additional information, see Note 17 – *Equity-Based Compensation*. These amounts do not correspond to the actual value that will be recognized by the executive.
- (2) These awards were granted on January 31, 2019 as a component of the 2018 bonus and vested immediately. The recipients of these awards received the Class A shares as a result of such vesting on February 7, 2020.
- (3) Vesting of the EPSs will occur in two parts, with one-half vesting on October 31, 2022 and the remaining one-half vesting on October 31, 2023, as long as Mr. Moler remains continuously employed by us through the vesting date.
- (4) Vesting of the EPSs will occur on December 31, 2020, as long as Mr. Brauchle remains continuously employed by us through the vesting date.
- (5) Vesting of the EPSs will occur in two parts, with one-half vesting on October 31, 2023 and the remaining one-half vesting on October 31, 2024, as long as such Named Executive Officer remains continuously employed by us through the vesting date.

Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Award Table

A narrative description of all material factors necessary to an understanding of the information included in the above Summary Compensation Table and Grants of Plan-Based Awards Table is included in "*Compensation Discussion and Analysis*" and in the footnotes to such tables.

Outstanding Equity Awards at Fiscal Year-End

The following table reflects all outstanding equity awards of our named executive officers as of December 31, 2019.

	Equity Participation Share Awards ⁽¹⁾			
	Number of Equity Participation Share Awards That Have Not Vested	Market Value of Equity Participation Share Awards That Have Not Vested ⁽²⁾	Number of Unearned Equity Participation Shares That Have Not Vested	Market or Payout Value of Unearned Equity Participation Shares That Have Not Vested ⁽²⁾
William R. Moler	250,000 ⁽³⁾	\$ 5,525,000	—	\$ —
Gary J. Brauchle	100,000 ⁽³⁾	\$ 2,210,000	—	\$ —
Christopher R. Jones	360,000 ⁽³⁾	\$ 7,956,000	—	\$ —
Gary D. Watkins	185,000 ⁽⁴⁾	\$ 4,088,500	—	\$ —

⁽¹⁾ The award agreements pursuant to which the equity participation shares set forth above were granted provide for the settlement of the equity participation shares in Class A shares.

⁽²⁾ Reflects the closing price of \$22.10 per Class A share at December 31, 2019.

⁽³⁾ Messrs. Moler, Brauchle, and Jones hold equity participation shares granted under the 2019 Grants described under "Elements of Compensation" above.

⁽⁴⁾ Mr. Watkins holds 35,000 equity participation shares under the 2018 Grants and 150,000 equity participation shares granted under the 2019 Grants, each as described under "Elements of Compensation" above.

Vested LTIP Awards

The following table sets forth certain information regarding the vesting of LTIP Awards during the fiscal year ended December 31, 2019.

	Number of Class A Shares Acquired on Vesting ⁽¹⁾	Value Realized on Vesting ⁽²⁾
William R. Moler <i>Chief Executive Officer and Director; Former President and Chief Operating Officer</i>	52,250 ⁽³⁾	\$ 1,193,333
Gary J. Brauchle <i>Executive Vice President and Chief Financial Officer</i>	36,650 ⁽³⁾	\$ 822,677
Christopher R. Jones <i>Executive Vice President, General Counsel and Secretary</i>	441,450 ⁽³⁾	\$ 8,388,725
Gary D. Watkins <i>Senior Vice President and Chief Accounting Officer</i>	150,400	\$ 3,174,504

⁽¹⁾ Represents the gross number of EPSs that vested during the year ended December 31, 2019. The actual number of Class A shares delivered to the Named Executive Officers was, in some cases, less than the number shown in the above table due to the withholding of Class A shares otherwise deliverable under the applicable award agreement to satisfy the tax withholding obligations related to the vesting of such EPSs.

⁽²⁾ The stated value realized upon vesting is computed by multiplying the closing market price of TGE's Class A shares on the date they vested by the number of units that vested.

⁽³⁾ Includes 23,250 EPSs granted to each of Messrs. Moler, Brauchle and Jones on January 31, 2019, which vested immediately upon grant, as an additional component of their 2018 bonus. Messrs. Moler, Brauchle and Jones were issued the Class A shares in respect of those awards on February 7, 2020 net of the Class A shares withheld to satisfy the tax withholding obligations related to the vesting of such EPSs.

Pension Benefits

We sponsor a 401(k) plan that is available to all employees, but we do not maintain a pension or defined benefit program.

Nonqualified Deferred Compensation and Other Nonqualified Deferred Compensation Plans

We do not have a nonqualified deferred compensation plan or program for our officers or employees.

Employment Agreements

Employment Agreement with William R. Moler

Effective November 24, 2019, our general partner and Tallgrass Management entered into an employment agreement with Mr. Moler (the "Moler Employment Agreement"), pursuant to which Mr. Moler has agreed to serve as the Chief Executive Officer of our general partner.

Under the terms of the Moler Employment Agreement, Mr. Moler is entitled to receive an annual salary of \$750,000 and was eligible to receive a bonus for the 2019 calendar year in the amount of \$1,500,000. For each subsequent calendar year, Mr. Moler will be eligible to receive annual bonuses, with a target amount for 2020 equal to 400% of his base salary, based on the achievement of performance targets established by the board of directors of our general partner, and subject to his continued employment through the date on which such bonus is paid.

Additionally, Mr. Moler is eligible for 18,132,145 Performance Awards. For a discussion of these Performance Awards, please read "*Elements of Compensation—Agreements to Grant Awards*" above.

While employed by our general partner, Mr. Moler is entitled to receive (i) benefits that are normally provided to senior executives of Tallgrass Management, (ii) reimbursement for all ordinary and necessary out-of-pocket business expenses incurred by Mr. Moler, and (iii) coverage under a policy of director and officer liability insurance. Mr. Moler's employment is "at will" and may be terminated at any time.

For a discussion of certain payments that Mr. Moler may be entitled to upon the termination of his employment, please read "*Potential Payments Upon Termination or Change-in-Control*" below.

Employment Agreement with Matthew Sheehy

Effective as of December 3, 2019, our general partner and Tallgrass Management entered into an employment agreement with Mr. Sheehy (the "Sheehy Employment Agreement"), pursuant to which Mr. Sheehy has agreed to serve as the President of our general partner.

Under the terms of the Sheehy Employment Agreement, Mr. Sheehy is entitled to receive an annual salary of \$500,000, which automatically increased to \$550,000 on January 1, 2020. The Sheehy Employment Agreement further provides that beginning with the 2020 calendar year and each subsequent calendar year, Mr. Sheehy will be eligible to receive annual bonuses, with a target amount for 2020 equal to 300% of his base salary, based on the achievement of performance targets established by the Board, and subject to his continued employment through the date on which such bonus is paid.

Additionally, Mr. Sheehy is eligible for 12,088,097 Performance Awards. For a discussion of the Performance Awards, please read "*Elements of Compensation—Agreements to Grant Awards*" above.

While employed by our general partner, Mr. Sheehy is entitled to receive (i) benefits that are normally provided to senior executives of Tallgrass Management, (ii) reimbursement for all ordinary and necessary out-of-pocket business expenses incurred by Mr. Sheehy, as well as reimbursement for the annual membership dues in YPO and one executive physical per year, and (iii) coverage under a policy of director and officer liability insurance. Mr. Sheehy's employment is "at will" and may be terminated at any time.

For a discussion of certain payments that Mr. Sheehy may be entitled to upon the termination of his employment, please read "*Potential Payments Upon Termination or Change-in-Control*" below.

Employment Agreement with Gary J. Brauchle

Effective May 3, 2019, our general partner and Tallgrass Management entered into an amended and restated employment agreement with Mr. Brauchle (the "Brauchle Employment Agreement"), pursuant to which Mr. Brauchle agreed to serve as the Executive Vice President and Chief Financial Officer of our general partner.

Under the terms of the Brauchle Employment Agreement, Mr. Brauchle is entitled to receive an annual salary of \$500,000 and will be eligible to receive bonuses for the 2019 calendar year and 2020 calendar year equal to a minimum of 100% of his base salary and a maximum of at least 300% of his base salary based on the achievement of performance targets established by the board of directors of our general partner. Mr. Brauchle must remain continuously employed by Tallgrass Management through December 31, 2019 and December 31, 2020 in order to receive bonus compensation with respect to such years. On January 14, 2020, Mr. Brauchle informed the board of directors of our general partner of his resignation as the Executive Vice President and Chief Financial Officer of our general partner effective on February 14, 2020. At the request of the board of

directors, Mr. Brauchle intends to remain with us in a non-executive capacity through the end of 2020 in order to facilitate his successor's transition to the role of Chief Financial Officer.

For a discussion of certain payments that Mr. Brauchle may be entitled to upon the termination of his employment, please read "*Potential Payments Upon Termination or Change-in-Control*" below.

Employment Agreement with Chris R. Jones

Effective March 11, 2019, our general partner and Tallgrass Management entered into an employment agreement with Mr. Jones (the "Jones Employment Agreement"), pursuant to which Mr. Jones has agreed to serve as the Executive Vice President, General Counsel and Secretary of our general partner.

Under the terms of the Jones Employment Agreement, Mr. Jones is entitled to receive an annual salary of \$500,000 and will be eligible to receive bonuses for the 2019 calendar year and 2020 calendar year equal to a minimum of 100% of his base salary and a maximum of at least 300% of his base salary based on the achievement of performance targets established by the board of directors of our general partner. In subsequent years, Mr. Jones will be eligible to receive discretionary bonus compensation. Mr. Jones must remain continuously employed by Tallgrass Management through the date on which bonuses are paid in order to receive such bonus compensation, except with respect to the bonuses for 2019 and 2020, which only require continued employment by Tallgrass Management through December 31 of the applicable year.

For a discussion of certain payments that Mr. Jones may be entitled to upon the termination of his employment, please read "*Potential Payments Upon Termination or Change-in-Control*" below.

Employment Agreement with Gary D. Watkins

Effective March 11, 2019, our general partner and Tallgrass Management entered into an employment agreement with Mr. Watkins (the "Watkins Employment Agreement"), pursuant to which Mr. Watkins has agreed to serve as the Vice President and Chief Accounting Officer of our general partner.

Under the terms of the Watkins Employment Agreement, Mr. Watkins is entitled to receive an annual salary of \$250,000 and will be eligible to receive bonuses for the 2019 calendar year and 2020 calendar year equal to a minimum of 100% of his base salary and a maximum of at least 150% of his base salary based on the achievement of performance targets established by the Board. In subsequent years, Mr. Watkins will be eligible to receive discretionary bonus compensation. Mr. Watkins must remain continuously employed by Tallgrass Management through the date on which bonuses are paid in order to receive such bonus compensation, except with respect to the bonuses for 2019 and 2020, which only require continued employment by Tallgrass Management through December 31 of the applicable year.

For a discussion of certain payments that Mr. Watkins may be entitled to upon the termination of his employment, please read "*Potential Payments Upon Termination or Change-in-Control*" below.

Employment Agreement with David G. Dehaemers, Jr.

Effective March 11, 2019, our general partner and Tallgrass Management entered into a third amended and restated employment agreement (the "Dehaemers Employment Agreement") with Mr. Dehaemers, which superseded and replaced his second amended and restated employment agreement. In connection with Mr. Dehaemers retirement as Chief Executive Officer of the general partner effective on November 24, 2019 and his retirement from the board of directors effective on December 31, 2019, Mr. Dehaemers remained employed by Tallgrass Management until December 31, 2019 and his retirement was not treated as a severance-triggering termination or voluntary resignation under the Dehaemers Employment Agreement. Mr. Dehaemers received his base salary through December 31, 2019 and his cash bonus compensation for the calendar year 2019, in each case, as provided in the Dehaemers Employment Agreement.

Potential Payments upon Termination or Change-in-Control

Termination

Termination of Mr. Moler

The Moler Employment Agreement provides that in the event Mr. Moler's employment is terminated without "cause" or in the event he resigns for "good reason", so long as he executes a release of claims and abides by his post-separation obligations, he will receive a severance payment equal to the sum of (i) his accrued but unpaid base salary immediately prior to the termination date, (ii) an amount equal to \$3,750,000, less any base salary earned for the year in which such termination occurs, payable in a lump sum within 60 days after the termination of his employment, (iii) two years of continued health care benefits, and (iv) if such termination or resignation occurs prior to October 31, 2022, accelerated vesting of 125,000 equity participation shares previously granted to Mr. Moler.

In addition, in the event Mr. Moler's employment is terminated without "cause" or in the event he resigns for "good reason" prior to December 31, 2024, so long as he executes a release of claims and abides by his post-separation obligations, (a) if such termination is on or within 12 months following a change of control, the Performance Awards will become fully vested; (b) if such termination is prior to a change of control or more than 12 months following a change of control, one-sixth of the Performance Awards will become fully vested; (c) after giving effect to the preceding clauses (a) and (b), Mr. Moler will forfeit all remaining unvested portions of the Performance Awards; and (d) Mr. Moler will retain all vested portions of the Performance Awards subject to the terms and conditions set forth in the Moler Employment Agreement and the applicable award documentation. Upon any termination or resignation, Mr. Moler would receive payments related to his accrued and unpaid expenses, salary and benefits, and is entitled to directors and officers liability insurance coverage for so long as he is subject to any claim arising from his employment by Tallgrass Management or service as a director of our general partner.

Termination of Mr. Sheehy

The Sheehy Employment Agreement provides that in the event Mr. Sheehy's employment is terminated without "cause" or in the event he resigns for "good reason", so long as he executes a release of claims and abides by his post-separation obligations, he will receive a severance payment equal to the sum of (i) his accrued but unpaid base salary and certain other accrued benefits immediately prior to the termination date, and (ii) an amount equal to one times the sum of (A) his base salary immediately prior to the termination date, and (B) the annual bonus he most recently received, payable in a lump sum within 60 days after the termination of his employment.

In addition, in the event Mr. Sheehy's employment is terminated without "cause" or in the event he resigns for "good reason" prior to December 31, 2024, so long as he executes a release of claims and abides by his post-separation obligations, (a) if such termination is on or within 12 months following a change of control, the Performance Awards will become fully vested; (b) if such termination is prior to a change of control or more than 12 months following a change of control, one-half of any unvested portion of the Performance Awards will become fully vested; (c) after giving effect to the preceding clauses (a) and (b), Mr. Sheehy will forfeit all remaining unvested portions of the Performance Awards; and (d) Mr. Sheehy will retain all vested portions of the Performance Awards subject to the terms and conditions set forth in the Sheehy Employment Agreement and the applicable award documentation. Upon any termination or resignation, Mr. Sheehy would receive payments related to his accrued and unpaid expenses, salary and benefits, and is entitled to directors and officers liability insurance coverage for so long as he is subject to any claim arising from his employment by Tallgrass Management.

Termination of Messrs. Brauchle, Jones and Watkins

The employment agreements for Messrs. Brauchle, Jones and Watkins provide that in the event his employment is terminated without "cause" or in the event he resigns for "good reason," so long as the executive executes a release of claims and abides by his post-separation obligations, he will receive a severance payment equal to two times the sum of (i) his base salary immediately prior to the termination date and (ii) the bonus he most recently received (or, if greater, the minimum bonus that would be payable in the year of termination notwithstanding his termination), payable in a lump sum within 60 days after the termination of his employment. Upon any termination or resignation, the executive would receive payments related to his accrued and unpaid expenses, salary and benefits, and is entitled to directors and officers liability insurance coverage for so long as he is subject to any claim arising from his employment by Tallgrass Management.

In addition, the Brauchle Employment Agreement provides that in the event Mr. Brauchle, in good faith, resigns other than for "good reason" between June 30, 2020 and December 31, 2020 and enters into a substantially full-time consulting arrangement with Tallgrass Management to facilitate the transition of the Chief Financial Officer role for the remainder of the 2020 calendar year, then, during the period of such consulting arrangement, he will remain eligible to receive generally the same salary, bonus, reimbursement of expenses and benefits to which he is entitled during the term of his employment by Tallgrass Management and will be eligible for continued vesting of certain equity awards that are scheduled to vest on December 31, 2020.

On January 14, 2020, Mr. Brauchle informed the board of directors of our general partner of his resignation as the Executive Vice President and Chief Financial Officer of our general partner effective on February 14, 2020. At the request of the board of directors, Mr. Brauchle intends to remain with us in a non-executive capacity through the end of 2020 in order to facilitate his successor's transition to the role of Chief Financial Officer.

Definition of "Cause" and "Good Reason"

Under the employment agreements with Messrs. Moler, Sheehy, Brauchle, Jones and Watkins:

- "Cause" means (i) the applicable executive's conviction of, or plea of nolo contendere to, any crime or offense constituting a felony under applicable law, other than motor vehicle violations for which no custodial penalty is imposed; (ii) the applicable executive's commission of fraud or embezzlement against Tallgrass Management or certain of its affiliates; (iii) gross neglect by the applicable executive of, or gross or willful misconduct of the applicable executive in connection with the performance of, his duties; (iv) the applicable executive's willful failure or refusal to carry out the reasonable and lawful instructions of the person to whom he reports; (v) the applicable executive's failure to perform the duties and responsibilities of his office as his primary business activity; (vi) a judicial determination that the applicable executive has breached his fiduciary duties with respect to Tallgrass Management or certain of its affiliates; or (vii) the applicable executive's willful and material breach of his obligations under any agreement between him and certain affiliates of Tallgrass Management that he fails to cure, if curable, within 30 days following written notice.
- "Good reason" means (i) a material diminution of the applicable executive's duties and responsibilities to Tallgrass Management or certain of its affiliates to a level inconsistent with those of his position; (ii) a material reduction in his cash compensation or the aggregate welfare benefits provided to him (excluding any reduction that is not limited to him specifically); (iii) with respect to Messrs. Moler, Brauchle, Jones and Watkins, a willful or intentional breach of the applicable employment agreement by Tallgrass Management, and with respect to Mr. Sheehy, a material breach of the Sheehy Employment Agreement by Tallgrass Management; (iv) with respect to Messrs. Moler and Sheehy, relocation of his primary work location to a location that is not within 30 miles of Leawood, Kansas and with respect to Messrs. Jones and Watkins, relocation of his primary work location to a location that is not within 30 miles of either Leawood, Kansas or Lakewood, Colorado; (v) with respect to Mr. Moler, his removal as a member of the board of directors of our general partner; and (vi) with respect to Mr. Moler, a merger of Tallgrass Management with another company that results in a reduction in his title, role or responsibilities.

Change in Control

Employment Agreement. Upon a change in control, the employment agreements with Messrs. Moler, Sheehy, Brauchle, Jones and Watkins do not provide for termination or severance benefits or payments in addition to those described above.

LTIP Award Agreements. In addition to the foregoing payments pursuant to the employment agreements, the 2018 Grants and the 2019 Grants provide for acceleration of vesting in connection with a change in control and if certain other conditions are met.

Under the Plans, "change of control" means the occurrence of one or more of the following events:

- any Person or group, other than Tallgrass Energy Holdings or its affiliates, becomes the owner, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of (A) the combined voting power of the equity interests in our general partner or (B) the general partner interests in TGE;
- the limited partners of TGE approve, in one or a series of transactions, a plan of complete liquidation of TGE; or
- the sale or other disposition by TGE of all or substantially all of its assets in one or more transactions to any person other than our general partner an affiliate of our general partner.

The 2018 Grants and the 2019 Grants include accelerated vesting if either (i) both (A) a qualifying transaction occurs, and (B) in connection with or within 12 months following such qualifying transaction, Mr. Dehaemers, Mr. Moler, Mr. Brauchle or Mr. Jones (excluding the name of the award recipient in such recipient's award agreement) cease to comprise at least one of the specified executive officer roles of our general partner or its affiliates, or (ii) (A) Mr. Dehaemers, Mr. Moler, Mr. Brauchle or Mr. Jones (excluding the name of the award recipient in such recipient's award agreement) cease to comprise at least one of the specified executive officer roles of our general partner or of its affiliates, and (B) within 2 years after the occurrence of such event, the award recipient is terminated without cause.

Under the award agreements for the 2018 Grants and 2019 Grants, a qualifying transaction means any transaction in which:

- a person other than certain designated persons directly or indirectly acquires direct or indirect ownership or control of more than 50% of the voting interests in our general partner, the ownership of more than 50% of the general partner interests in TGE, or the ownership of such other rights or interests that grant to the owner or holder thereof the ability to direct the management or policies of TGE, whether through the ownership of voting rights, by contract, or otherwise, or if TGE becomes a corporation or limited liability company or if the limited partners of TGE become eligible to elect the members of the board of our general partner, the direct or indirect ability to appoint a majority of the board of directors of the corporation or limited liability company or the board of our general partner, as the case may be.
- TGE's limited partners approve, in one or a series of transactions, a plan of complete liquidation of TGE; or

- the sale or other disposition by TGE of all or substantially all of its assets in one or more transactions to any person other than our general partner and its affiliates.

A qualifying transaction has occurred under the 2018 Grants as a result of the March 2019 Blackstone Acquisition. However, the other conditions for the acceleration of the 2018 Grants have not been met as of February 12, 2020.

The following table sets forth the value of outstanding LTIP Awards that would have vested and/or become exercisable for each of the Named Executive Officers under the Plans if a triggering change in control event described above occurred on December 31, 2019.

	Upon a Change in Control ⁽¹⁾
William R. Moler	\$ 5,525,000
David G. Dehaemers, Jr.	\$ —
Matthew Sheehy	\$ —
Gary J. Brauchle	\$ 2,210,000
Christopher R. Jones	\$ 7,956,000
Gary D. Watkins	\$ 4,088,500

- ⁽¹⁾ The stated value upon a change in control is computed by assuming that a triggering change of control event occurred on December 31, 2019 and multiplying the closing market price (\$22.10) of the Class A shares on such date by the number of Class A shares that would have vested.

Confidentiality, Non-Compete and Non-Solicitation Arrangements

Each of the employment agreements with the Named Executive Officers include agreements of such executive to not disclose our confidential information. Further, each of the Named Executive Officers other than Mr. Sheehy have also signed a confidentiality agreement in connection with their employment by Tallgrass Management.

In addition, each of the employment agreements with the Named Executive Officers includes non-competition and non-solicitation arrangements, as follows:

- Messrs. Moler and Sheehy have agreed not to compete with Tallgrass Management or certain of its affiliates and not to solicit Tallgrass Management's or certain of its affiliates' employees during the term of his employment and for a period of two years thereafter.
- Mr. Brauchle has agreed (i) not to compete with Tallgrass Management or certain of its affiliates through certain specified competitors or acquirors during the term of his employment and for a period of one year thereafter, or (ii) not to solicit Tallgrass Management's or any of its affiliates' employees or interfere with certain business relationships during the term of his employment and for a period of one year thereafter.
- Messrs. Jones and Watkins have agreed not to compete with Tallgrass Management or certain of its affiliates and not to solicit Tallgrass Management's or any of its affiliates' employees or interfere with certain business relationships during the term of their employment and (i) in the event employment terminates on or before December 31, 2020, for a period of two years thereafter or (ii) in the event employment terminates after December 31, 2020, until the later of December 31, 2022 and one year after such termination.
- Mr. Dehaemers has agreed not to compete with Tallgrass Management or certain of its affiliates and not to solicit Tallgrass Management's or any of its affiliates' employees or interfere with certain business relationships during the term of his employment and service as a director of TGE GP and generally for three years thereafter.

Further, the award agreements governing the 2018 Grants to Mr. Watkins, and certain equity participation shares to Messrs. Jones and Watkins that vested in November 2019, include an agreement by such executive not to compete with our general partner and its affiliates for the period commencing on the grant date and ending upon the earlier of (i) if a vesting date occurs, 18-months following termination of such person's employment, (ii) the date such LTIP Awards are forfeited without vesting, and (iii) the date such LTIP Awards expire.

Compensation of TGE Directors

Officers or employees of our general partner or its affiliates, including certain directors affiliated with the Sponsor Entities, who serve as directors of our general partner do not receive additional compensation for such service. In 2019, those directors of our general partner who were not excluded from receiving compensation were paid cash compensation consisting of (i) a

quarterly cash payment of \$10,000 with respect to the first quarter of 2019, and (ii) a quarterly cash payment of \$20,000 with respect to the remaining quarters of 2019. All directors are also reimbursed for out-of-pocket expenses in connection with their service as directors, including costs incurred to attend meetings.

Directors of our general partner are also eligible to receive grants under the Plans. As part of regular director compensation, each of the four independent directors received grants of 3,000 equity participation shares in June 2019 and Mr. Gerke received a grant of 3,600 equity participation shares in February 2019.

Each director is fully indemnified by us for actions associated with being a director to the fullest extent permitted under Delaware law pursuant to our partnership agreement. Further, we and our general partner entered into indemnification agreements (collectively, the "Director Indemnification Agreements") with each of the directors of our general partner effective March 11, 2019. Under the terms of the Director Indemnification Agreements, we agree to indemnify and hold each director (collectively, the "Indemnitees") harmless from and against any and all losses, claims, damages, liabilities, judgments, fines, taxes (including ERISA excise taxes), penalties (whether civil, criminal, or other), interest, assessments, amounts paid or payable in settlements, or other amounts and any and all "expenses" (as defined in the Director Indemnification Agreements) arising from any and all threatened, pending, or completed claims, demands, actions, suits, proceedings, or alternative dispute mechanisms, whether civil, criminal, administrative, arbitral, investigative, or otherwise, whether made pursuant to federal, state, or local law, whether formal or informal, and including appeals, in each case, which the Indemnitee may be involved, or is threatened to be involved, as a party, a witness, or otherwise, including any inquiries, hearings, or investigations, related to the fact that Indemnitee is or was a director of our general partner or is or was serving at the request of our general partner or us as a manager, managing member, general partner, director, officer, fiduciary, trustee, or agent of any other entity, organization, or person of any nature. We have also agreed to advance the expenses of an Indemnitee relating to the foregoing. To the extent that a change in the laws of the State of Delaware permits greater or lesser indemnification under any statute, agreement, organizational document, or governing document than would be afforded under the Director Indemnification Agreements as of the date of the Director Indemnification Agreements, the Indemnitee shall enjoy or be subject to the greater or lesser benefits so afforded by such change.

The following table sets forth certain information with respect to our non-employee directors receiving cash compensation during the year ended December 31, 2019:

Name and Principal Position	Fees Earned	Equity Participation Share Awards ⁽¹⁾	Non-Equity Incentive Plan Compensation	Total
Thomas A. Gerke	\$ 70,000	\$ 129,428	\$ —	\$ 199,428
Roy N. Cook	\$ 70,000	\$ 58,700	\$ —	\$ 128,700
Terrance D. Towner.....	\$ 70,000	\$ 58,700	\$ —	\$ 128,700
Guy G. Buckley.....	\$ 60,000	\$ 58,700	\$ —	\$ 118,700

- ⁽¹⁾ The amounts in this column include equity participation shares granted pursuant to the Plans. These amounts represent the aggregate grant date fair value determined in accordance with ASC Topic 718 for equity participation shares granted under the Plans. Pursuant to SEC rules, the amounts shown in the table above for awards subject to performance conditions are based on the probable outcome as of the date of grant and exclude the impact of estimated forfeitures. The EPSs are non-participating, therefore the grant date fair value is discounted from the grant date fair value of TGE's Class A shares, as appropriate, for the present value of the expected (but non-participating) future dividends during the vesting period. For additional information, see Note 17 – *Equity-Based Compensation*. These amounts do not correspond to the actual value that will be recognized by the directors.

Compensation Committee Interlocks and Insider Participation

The listing rules of the NYSE do not require us to maintain, and we do not maintain, a compensation committee.

Our Chief Executive Officer participates in the deliberations of the board of directors of our general partner concerning executive officer compensation in his capacity as a director of our general partner. In addition, our Chief Executive Officer makes recommendations to the board of directors regarding named executive officer compensation, but is not present for any discussions regarding his performance or compensation.

Compensation Report of the Board of Directors

The board of directors of our general partner has reviewed and discussed the compensation discussion and analysis contained in this Annual Report on Form 10-K with management and, based on that review and discussion, has recommended that the compensation discussion and analysis be included in this Annual Report for the year ended December 31, 2019 for filing with the SEC.

William R. Moler
Marcelino Oreja Arburúa
Guy G. Buckley
Roy N. Cook
Thomas A. Gerke
Wallace C. Henderson
Matthew J.K. Runkle
Terrance D. Towner

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

Tallgrass Energy, LP

The following tables set forth certain information regarding the beneficial ownership of our Class A shares and Class B shares as of February 10, 2020 owned by:

- each person who is known to us to beneficially own more than 5% of the Class A shares (calculated in accordance with Rule 13d-3);
- the named executive officers of our general partner;
- each of the directors of our general partner; and
- all the directors and executive officers of our general partner as a group.

All information with respect to beneficial ownership has been furnished by the respective directors, officers or 5% or more shareholders, as the case may be. The amounts and percentage of Class A shares and Class B shares beneficially owned are reported on the basis of SEC regulations governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a "beneficial owner" of a security if that person has or shares "voting power," which includes the power to vote or to direct the voting of such security, or "investment power," which includes the power to dispose of or to direct the disposition of such security. Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all Class A shares and Class B shares shown as beneficially owned by them, subject to community property laws where applicable. Unless otherwise noted, the address of each beneficial owner named in the chart below is 4200 W. 115th Street, Suite 350, Leawood, Kansas 66211, Attn: General Counsel.

Name and Address of Beneficial Owner	Class A and Class B shares Beneficially Owned ⁽¹⁾	Percentage of Class A and Class B shares Beneficially Owned ⁽²⁾	Combined Voting Power ⁽³⁾
5% shareholders			
Blackstone ⁽⁴⁾	124,307,584	44.35%	44.12%
Jasmine Ventures Pte. Ltd. ⁽⁵⁾	124,307,584	44.35%	44.12%
Enagás ⁽⁶⁾	124,307,584	44.35%	44.12%
Tortoise Capital Advisors, L.L.C. ⁽⁷⁾	17,044,629	9.49%	6.05%
Directors and named Executive officers:			
William R. Moler ⁽⁸⁾	1,515,616	*	*
Matthew Sheehy	—	—%	—%
Gary J. Brauchle ⁽⁹⁾	707,343.41	*	*
Christopher R. Jones ⁽¹⁰⁾	447,441	*	*
Gary D. Watkins	74,044	*	*
David G. Dehaemers, Jr. ⁽¹⁰⁾	1,806,319	1.01%	*
Terrance D. Towner	56,600	*	*
Roy N. Cook	120,165	*	*
Thomas A. Gerke	57,900	*	*
Marcelino Oreja Arburúa	—	—%	—%
Guy G. Buckley	—	—%	—%
Wallace C. Henderson	—	—%	—%
Matthew J.K. Runkle	—	—%	—%
All directors and executive officers of our general partner as a group (13 persons)	4,785,428.41	2.65%	1.70%

* Less than 1%.

- (1) Pursuant to Rule 13d-3 under the Exchange Act, a person has beneficial ownership of a security as to which that person, directly or indirectly, through any contract, arrangement, understanding, relationship, or otherwise has or shares voting power and/or investment power of such security and as to which that person has the right to acquire beneficial ownership of such security within 60 days. In addition to Class A shares, this column includes Class B shares beneficially owned by such persons that are, together with a corresponding number of TE Units, exchangeable at any time and from time to time for Class A shares on a one-for-one basis (subject to the terms of the Tallgrass Equity limited liability company agreement and our partnership agreement). See "*Certain Relationships and Related Transactions, and Director Independence-Exchange Right.*"
- (2) The Class A shares to be issued upon the exchange of Class B shares and TE Units as described in footnote (1) above are deemed to be outstanding and beneficially owned by the person holding the Class B shares for the purpose of computing the percentage of beneficial ownership of Class A shares for that person and any group of which that person is a member, but are not deemed outstanding for purpose of computing the percentage of beneficial ownership of any other person. As such, the percentage of Class A shares shown as being beneficially owned by each person is based on an assumption that each such person exchanged all of such person's Class B shares, together with a corresponding number of TE Units, for Class A shares and that no other person made a similar exchange.
- (3) Represents the percentage of voting power of the Class A shares and Class B shares held by such person voting together as a single class.
- (4) Amounts beneficially owned reflect 21,751,018 Class A shares directly held by Prairie Non-ECI Acquiror LP, a Delaware limited partnership ("Class A Acquiror"), 773,510 Class A shares directly held by Prairie Secondary Acquiror LP, a Delaware limited partnership ("Secondary Acquiror 1"), 1,127,935 Class A shares directly held by Prairie Secondary Acquiror E LP, a Delaware limited partnership ("Secondary Acquiror 2" and, together with Secondary Acquiror 1, the "Prairie Secondary Acquirors"), 92,778,793 Class B shares and TE Units directly held by Prairie ECI Acquiror LP, a Delaware limited partnership ("Up-C Acquiror 1"), and 7,876,328 Class B shares and TE Units directly held by Prairie VCOC Acquiror LP, a Delaware limited partnership ("Up-C Acquiror 2" and, together with Up-C Acquiror 1, the "Up-C Acquirors").

Holdings Manager is the general partner of Class A Acquiror and each of the Up-C Acquirors and Prairie Secondary Acquirors. Blackstone Infrastructure Associates L.P., a Delaware limited partnership ("Blackstone Infrastructure"), is the managing member of Holdings Manager. BIA GP L.P. is the general partner of Blackstone Infrastructure. BIA GP L.L.C. is the general partner of BIA GP L.P. Blackstone Holdings II L.P. is the sole member of BIA GP L.L.C. Blackstone Holdings I/II GP L.L.C. is the general partner of Blackstone Holdings II L.P. The Blackstone Group Inc. is the sole member of Blackstone Holdings I/II GP L.L.C. Blackstone Group Management L.L.C. is the sole holder of the Class C common stock of The Blackstone Group Inc. Blackstone Group Management L.L.C. is wholly-owned by Blackstone's senior managing directors and controlled by its founder, Stephen A. Schwarzman.

Each of the Blackstone entities described in this footnote and Stephen A. Schwarzman (other than to the extent it or he directly holds securities as described herein) may be deemed to beneficially own the securities directly or indirectly controlled by such Blackstone entities or him, but each disclaims beneficial ownership of such shares. The address of each of Mr. Schwarzman and each of the other entities listed in this footnote is c/o The Blackstone Group Inc., 345 Park Avenue, New York, New York 10154.

As of January 17, 2020, certain Blackstone entities have pledged, hypothecated or granted security interests in all of the Class A shares, Class B shares and TE Units held by Class A Acquiror and the Up-C Acquirors pursuant to a credit agreement with customary default provisions. In the event of a default under the credit agreement, the secured parties may foreclose upon any and all Class A shares, Class B shares and TE Units pledged to them and may seek recourse against the borrowers thereunder.

- (5) Amounts beneficially owned reflect Class A shares and Class B shares reported in footnote (4) above. Pursuant to the Equityholders Agreement, the consent of Jasmine is required in certain circumstances for Holdings Manager to direct the voting and disposition of the securities held by the Class A Acquiror, Prairie Secondary Acquirors and Up-C Acquirors. Jasmine is controlled and managed by GIC Special Investments Pte. Ltd. ("GIC SI"), which is a wholly owned subsidiary of GIC Private Limited ("GIC"). In such capacities, each of GIC SI and GIC shares with Jasmine the power to vote and dispose of the Class A shares and Class B shares deemed to be beneficially owned by Jasmine. Each of Jasmine, GIC SI and GIC expressly disclaims beneficial ownership of any such Class A shares or Class B shares. The principal business address for each of Jasmine, GIC SI and GIC is 168, Robinson Road, #37-01 Capital Tower, Singapore 068912.
- (6) Amounts beneficially owned reflect Class A shares and Class B shares reported in footnote (4) above. Pursuant to the Equityholders Agreement, the consent of Enagás Holding USA, S.L.U. ("Enagás Spain") and Enagas U.S.A. LLC ("Enagas USA") is required in certain circumstances for Holdings Manager to direct the voting and disposition of the securities held by the Class A Acquiror, Prairie Secondary Acquirors and Up-C Acquirors. Enagás is the sole shareholder of Enagás Internacional, S.L.U. ("Enagás Internacional"), which is the sole shareholder of Enagás Spain, which is the sole member of Enagas USA. As a result, each of Enagás, Enagás Internacional, Enagás Spain and Enagas USA may be deemed to beneficially own the Class A shares, Class B shares and TE Units held by Class A Acquiror, the Prairie Secondary Acquirors and Up-C Acquirors. The principal business address of Enagas USA is 850 New Burton Road, Suite 201, Dover, DE 19904. The principal business address of each of Enagás, Enagás Internacional and Enagás Spain is Paseo de los Olmos, 19, 28005 Madrid, Spain.
- (7) As reported on Schedule 13G filed with the SEC on August 6, 2019. Tortoise Capital Advisors, L.L.C. ("TCA") acts as an investment advisor to certain investment companies registered under the Investment Company Act of 1940. TCA, by virtue of investment advisory agreements with these investment companies, has all investment and voting power over securities owned of record by these investment companies. However, despite their delegation of investment and voting power to TCA, these investment companies may be deemed to be the beneficial owners under Rule 13d-3 of the Act, of the securities they own of record because they have the right to acquire investment and voting power through termination of their investment advisory agreement with TCA. Thus, TCA has reported on the Schedule 13G that it shares voting power and dispositive power over the securities owned of record by these investment companies. TCA also acts as an investment adviser to certain managed accounts. Under contractual agreements with these managed account clients, TCA, with respect to the securities held in these client accounts, has investment and voting power with respect to certain of these client accounts, and has investment power but no voting power with respect to certain other of these client accounts. TCA has reported on the Schedule 13G that it shares voting and/or investment power over the securities held by these client managed accounts despite a delegation of voting and/or investment power to TCA because the clients have the right to acquire investment and voting power through termination of their agreements with TCA. TCA may be deemed the beneficial owner of the securities covered by the Schedule 13G under Rule 13d-3 of the Act that are held by its clients. The business address for this person is 11550 Ash Street, Suite 300, Leawood, Kansas 66211.
- (8) Consists of (i) 16,328 Class A shares held directly by Mr. Moler, and (ii) 1,499,288 Class A shares held indirectly by Mr. Moler through the William R. Moler Revocable Trust U.T.A. dated August 27, 2013, for which Mr. Moler serves as trustee. Mr. Moler disclaims beneficial ownership of such 1,499,288 Class A shares except to the extent of his pecuniary interest therein.

- (9) Consists of (i) 16,258 Class A shares held directly by Mr. Brauchle, and (ii) 145,176.41 Class A shares and 545,909 Class B shares held indirectly by Mr. Brauchle under trust agreement dated April 10, 2014, for which Mr. Brauchle serves as the Trustee. Mr. Brauchle disclaims beneficial ownership of such Class B shares except to the extent of his pecuniary interest therein.
- (10) Consists of (i) 343,458 Class A shares held directly by Mr. Jones, and (ii) 103,983 Class B shares held indirectly by Mr. Jones through the Amended and Restated Christopher R. Jones Revocable Trust under Trust Indenture dated March 6, 2019. Mr. Jones disclaims beneficial ownership of such Class B shares except to the extent of his pecuniary interest therein.
- (11) Class A shares held indirectly by Mr. Dehaemers through the David G. Dehaemers, Jr. Revocable Trust, dated April 26, 2006, for which Mr. Dehaemers serves as trustee. Mr. Dehaemers disclaims beneficial ownership of such Class A shares except to the extent of his pecuniary interest therein.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information about our Class A shares that may be issued under equity compensation plans as of December 31, 2019:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted average grant date fair value of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	3,883,000 ⁽¹⁾	\$ 17.85	15,381,004
Equity compensation plans not approved by security holders ⁽²⁾	—	\$ —	—
Total	3,883,000	\$ 17.85	15,381,004

(1) Amounts shown represent EPS awards outstanding under the Plans as of December 31, 2019. The outstanding awards will be settled in Class A shares pursuant to the terms of the award agreements and are not subject to an exercise price.

(2) There are no equity compensation plans in place pursuant to which Class A shares may be issued except for the Plans.

For additional information regarding the Plans, see Note 17 – *Equity-Based Compensation* to our Consolidated Financial Statements in Item 8.—Financial Statements and Supplementary Data of this Annual Report.

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

We are a Delaware limited partnership formed in February 2015. Although we were formed as a limited partnership, we have elected to be taxed as a corporation for U.S. federal income tax purposes.

Limited Liability Company Agreement of Tallgrass Equity

As of February 12, 2020, we own TE Units representing 63.75% of the membership interests in Tallgrass Equity. In accordance with the Tallgrass Equity limited liability company agreement, the net profits and net losses of Tallgrass Equity will generally be allocated to the holders of TE Units on a pro rata basis in accordance with their relative number of TE Units held. Accordingly, net profits and losses of Tallgrass Equity are currently allocated 63.75% to us and 36.25% to the Exchange Right Holders with respect to their TE Units. If we cause a distribution to be made, such distribution will be made to the holders of TE Units on a pro rata basis in accordance with their relative number of TE Units held.

For purposes of any transfer or exchange of TE Units initially owned by the Exchange Right Holders and our Class B shares, the Tallgrass Equity limited liability company agreement and our partnership agreement contain provisions linking each such TE Unit with one of our Class B shares. Our Class B shares cannot be transferred without transferring an equal number of TE Units and vice versa.

In addition, pursuant to our partnership agreement and the Tallgrass Equity limited liability company agreement, our capital structure and the capital structure of Tallgrass Equity generally replicate one another and provide for customary antidilution mechanisms in order to maintain the one-for-one exchange ratio between the TE Units and Class B shares, on the one hand, and our Class A shares, on the other hand.

Exchange Right

The Exchange Right Holders and any permitted transferees of their TE Units each have the right to exchange all or a portion of their TE Units into Class A shares at an exchange ratio of one Class A share for each TE Unit exchanged, which we refer to as the Exchange Right. The Exchange Right may be exercised only if, simultaneously therewith, an equal number of our Class B shares are transferred by the exercising party to us. Upon such exchange, we will cancel the Class B shares received from the exercising party.

For purposes of any transfer or exchange of TE Units initially owned by the Exchange Right Holders and our Class B shares, the Tallgrass Equity limited liability company agreement and our partnership agreement contain provisions effectively linking one TE Unit with one of our Class B shares. Class B shares cannot be transferred without transferring an equal number of TE Units and vice versa. During the year ended December 31, 2019, 21,751,018 Class A shares were issued and an equal number of Class B shares were cancelled as a result of the exercise of the Exchange Right. During the year ended December 31, 2018, 2,821,332 Class A shares were issued and an equal number of Class B shares were cancelled as a result of the exercise of the Exchange Right.

The above mechanisms are subject to customary conversion rate adjustments for equity splits, equity dividends and reclassifications.

Registration Rights Agreement

In connection with the closing of the TGE initial public offering, we entered into a Registration Rights Agreement dated as of May 12, 2015 (the "Original Registration Rights Agreement") with certain of the Exchange Right Holders at the time. Pursuant to the Original Registration Rights Agreement, we agreed to register the resale of 109,504,440 Class A shares issuable upon exercise of the Exchange Right held by certain Class B shareholders or any of their permitted transferees to the registration rights agreement under certain circumstances. In addition, we subsequently agreed to register the 27,554,785 Class A shares issuable upon the exercise of the Exchange Right with respect to 27,554,785 TE Units and Class B shares, respectively, issued in connection with the acquisition of 25.01% membership interest in Rockies Express and 5,619,218 additional TEP common units by Tallgrass Equity in February 2018.

In connection with the closing of the March 2019 Blackstone Acquisition, certain of the Sellers assigned to certain of the Sponsor Entities their respective registration rights under the Original Registration Rights Agreement with respect to the Class A shares purchased directly by such Sponsor Entities and the Class A shares issuable upon exchange of the TE Units and Class B shares purchased by such Sponsor Entities pursuant to the Purchase Agreement. Immediately following the closing of the March 2019 Blackstone Acquisition, we, certain Sponsor Entities and certain current and former members of our management entered into an Amended and Restated Registration Rights Agreement dated as of March 11, 2019 (the "Amended and Restated Registration Rights Agreement"), pursuant to which we agreed to register the resale of any Class A shares held by certain Sponsor Entities, certain current and form members of our management or any of their permitted transferees, including those Class A shares issuable upon the exercise of the Exchange Right, under certain circumstances (such Class A shares, the "Registrable Securities").

In accordance with our obligations under the Original Registration Rights Agreement, as subsequently amended and restated by the Amended and Restated Registration Rights Agreement, we have registered the resale of 125,291,659 Class A shares, 102,136,875 of which remain issuable upon exercise of the Exchange Right, pursuant to our Form S-3 (File No. 333-225382) filed with the SEC on June 1, 2018, which became effective June 13, 2018. We are required to maintain the effectiveness of such registration statement until the date on which all Registrable Securities covered by the shelf registration statement have been sold thereunder in accordance with the plan and method of distribution disclosed in the annual report included in the shelf registration statement, or otherwise cease to be Registrable Securities under the Amended and Restated Registration Rights Agreement.

Demand and Piggyback Rights

The Exchange Right Holders have the right to require that we register their Registrable Securities and/or facilitate an underwritten offering of their Registrable Securities. There is no aggregate limit on the number of such demand requests; however, the demand rights of these holders are subject to a number of size, frequency and other limitations.

In the event we propose to conduct an underwritten offering of Registrable Securities, then the holders of Registrable Securities will generally have customary rights to participate in such offering, subject to customary offering size limitations and related allocation provisions and other limitations. Similarly, in the event that eligible holders demand that we conduct an underwritten offering of their Registrable Securities, then we will generally have customary rights to participate in such offering, subject to customary offering size limitations and related allocation provisions and other limitations.

Delay Rights

We will not be required to comply with any demand request, and may suspend the holders' ability to use any shelf registration statement, following our delivery of written notice to the holders of customary blackout periods and deferral events.

Expenses

The holders of Registrable Securities will pay certain selling expenses, including any underwriters' discounts and commissions. We will generally cause Tallgrass Equity to pay all other registration expenses in connection with our obligations under the registration rights agreement.

TGE Omnibus Agreement

In connection with the closing of the TGE initial public offering in May 2015, we, our general partner, Tallgrass Equity and Tallgrass Energy Holdings entered into the TGE Omnibus Agreement, that addressed the following matters:

- Tallgrass Equity's obligation to reimburse Tallgrass Energy Holdings and its affiliates for expenses incurred (i) on our behalf, (ii) on behalf of our general partner and (iii) for any other purposes related to our business and activities or those of our general partner, including our public company expenses and general and administrative expenses; and
- Our use of the name "Tallgrass" and any associated or related marks.

Pursuant to the TGE Omnibus Agreement, Tallgrass Energy Holdings was permitted to perform, or cause its affiliates to perform, centralized general and administrative services for TGE, such as accounting, audit, business development, corporate record keeping, treasury services (including cash management), real property/land, legal, operations/engineering, investor relations, risk management, commercial/marketing, information technology, insurance, government relations/compliance, tax, payroll, human resources and environmental, health and safety. In exchange, Tallgrass Equity reimbursed Tallgrass Energy Holdings and its affiliates for their expenses to the extent incurred on our behalf in providing these services. All reimbursements to our general partner, Tallgrass Energy Holdings and their respective affiliates by Tallgrass Equity proportionally reduced cash distributions by Tallgrass Equity to its members, which in turn reduced the amount of cash we distribute to our Class A shareholders.

From January 1, 2018 until March 11, 2019, these costs were incurred by Tallgrass Equity directly. Effective March 11, 2019, the TGE Omnibus Agreement was terminated in connection with the closing of the March 2019 Blackstone Acquisition.

TEP Omnibus Agreement

In May 2013, TEP entered into an Omnibus Agreement with Tallgrass Equity (as successor to Tallgrass Development), Tallgrass Energy Holdings, and TEP GP, which we refer to as the TEP Omnibus Agreement, that governed TEP's relationship with them regarding the following matters:

- the provision by Tallgrass Energy Holdings to TEP of certain administrative services and TEP's agreement to reimburse it for such services;
- the provision by Tallgrass Energy Holdings of such employees as may be necessary to operate and manage TEP's business, and TEP's agreement to reimburse it for the expenses associated with such employees;
- certain indemnification obligations; and
- TEP's use of the name "Tallgrass" and related marks.

Pursuant to the TEP Omnibus Agreement, Tallgrass Energy Holdings was permitted to perform, or causes its affiliates to perform, centralized corporate, general and administrative services for TEP, such as legal, corporate record keeping, planning, budgeting, regulatory, accounting, billing, business development, treasury, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, investor relations, cash management and banking, payroll, internal audit, taxes and engineering. In exchange, TEP reimbursed Tallgrass Energy Holdings and its affiliates for their expenses to the extent incurred on TEP's behalf in providing these services.

From January 1, 2018 until March 11, 2019, these costs were incurred by TEP directly and, in the case of certain employee compensation and benefits, paid on TEP's behalf by its affiliate, Tallgrass Management. Effective March 11, 2019, the TEP Omnibus Agreement was terminated in connection with the closing of the March 2019 Blackstone Acquisition.

Take Private Merger Agreement

See discussion of the Take Private Merger Agreement in Item 1.-Business, "*Organizational Structure*," which is incorporated by reference into this Item 13 of this Annual Report.

Support Agreement

Contemporaneously with the execution and delivery of the Take Private Merger Agreement, certain Sponsor Entities entered into a support agreement (the "Support Agreement") with us, pursuant to which such Sponsor Entities agreed to vote the 23,652,463 Class A shares and 100,655,121 Class B shares (representing approximately 44.1% of the total voting power of TGE's outstanding voting securities as of December 31, 2019) held of record and beneficially by the Sponsor Entities in favor of the approval of the Take Private Merger Agreement and the transactions contemplated thereby at any meeting of the our shareholders and against any Alternative Proposal (as defined in the Support Agreement).

Procedures for Review, Approval or Ratification of Transactions with Related Persons

The board of directors of our general partner has adopted a related party transactions policy (the "Policy"), which supplements the conflict of interest provisions in our code of business conduct and ethics. According to the Policy, a "Related Party Transaction" is an actual or proposed transaction, arrangement or relationship (or any series of similar transactions, arrangements or relationships) in which (a) the Partnership, our general partner or Tallgrass Equity (collectively, the "Partnership Group") was, is or will be a participant, (b) the amount involved exceeds \$120,000, and (c) in which any Related Party had, has or will have a direct or indirect material interest. The Policy's definition of a "Related Party" is in line with the definition set forth in the instructions to Item 404(a) of Regulation S-K promulgated by the SEC. Transactions resolved under the conflicts provisions of our partnership agreement are not required to be reviewed or approved under the policy.

Under the Policy, the General Counsel and Chief Financial Officer or Chief Accounting Officer are responsible for determining whether a Related Party Transaction requires the approval of the Audit Committee. The Audit Committee is responsible for evaluating and assessing a proposed transaction based on the relevant facts and circumstances, including comparing the terms of the proposed transaction to the terms available to unrelated third parties. The Audit Committee shall approve only those Related Party Transactions that are either (i) on terms no less favorable to the Partnership Group than those generally being provided to or available from unrelated third parties or (ii) are fair and reasonable to the Partnership Group, taking into account the totality of the relationships between the parties involved.

If the General Counsel determines it is impractical or undesirable to wait until an Audit Committee meeting to consummate a Related Party Transaction, the chairman of the Audit Committee may review and approve the Related Party Transaction in accordance with the procedures set forth in the Policy. However, any such approval (and its rationale) must be reported to the Audit Committee at the next regularly scheduled meeting. A Related Party Transaction entered into without pre-approval of the Audit Committee shall not be deemed to violate the Policy, or be invalid or unenforceable, so long as the transaction is brought to the Audit Committee as promptly as reasonably practical after it is entered into and is subsequently ratified by the Audit Committee. If the Audit Committee determines not to ratify a Related Party Transaction that has been commenced without approval, the Audit Committee may direct the immediate discontinuation or rescission of the transaction, or modify the transaction to make it acceptable for ratification.

Director Independence

The information required by Item 407(a) of Regulation S-K is included in Item 10.—Directors, Executive Officers and Corporate Governance.

Item 14. Principal Accounting Fees and Services

We have engaged Deloitte & Touche LLP as our independent registered public accounting firm for the year ended December 31, 2019. We engaged PricewaterhouseCoopers LLP as our independent registered public accounting firm for the year ended December 31, 2018. The following table summarizes fees we were billed by Deloitte & Touche LLP and PricewaterhouseCoopers LLP, respectively, for independent auditing, tax and related services for each of the last two fiscal years:

	Year Ended December 31,	
	2019	2018
	(in thousands)	
Audit fees ⁽¹⁾	\$ 1,127	\$ 1,935
Audit related fees ⁽²⁾	—	—
Tax fees ⁽³⁾	382	520
Total	\$ 1,509	\$ 2,455

- (1) Audit fees represent amounts billed for each of the years presented for professional services rendered in connection with (i) the integrated audit of our annual financial statements and internal control over financial reporting, (ii) the review of our quarterly financial statements or (iii) those services normally provided in connection with statutory and regulatory filings or engagements including comfort letters, consents and other services related to SEC matters. This information is presented as of the latest practicable date for this Annual Report.
- (2) Audit-related fees represent amounts we were billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews of our financial statements and are not reported under audit fees.
- (3) Tax fees represent amounts we were billed by PricewaterhouseCoopers LLP in each of the years presented for professional services rendered in connection with tax compliance, tax advice and tax planning.

All services provided by our independent registered public accountant are subject to pre-approval by the audit committee of our general partner. The audit committee of our general partner is informed of each engagement of the independent registered public accountant to provide services under the policy. The audit committee of our general partner has approved the use of Deloitte & Touche LLP as our independent registered public accounting firm, including all services rendered for the year ended December 31, 2019.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(1) Financial Statements

Financial Statements included in this Item 15:

Financial Statements of Rockies Express Pipeline LLC

FINANCIAL STATEMENTS

*ROCKIES EXPRESS
PIPELINE LLC*

For the years ended December 31, 2019, 2018 and 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors of Rockies Express Pipeline LLC

We have audited the accompanying financial statements of Rockies Express Pipeline LLC (the "Company"), which comprise the balance sheet as of December 31, 2019, and the related statements of income, members' equity, and cash flows for the year then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Rockies Express Pipeline, LLC as of December 31, 2019, and the results of its operations and its cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America.

Emphasis of Matter

As discussed in Notes 2 and 8 to the financial statements, in 2019, the Company adopted new accounting guidance related to leases. Our opinion is not modified with respect to this matter.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 12, 2020

Report of Independent Registered Public Accounting Firm

To the Board of Directors of Rockies Express Pipeline LLC

We have audited the accompanying financial statements of Rockies Express Pipeline LLC, which comprise the balance sheet as of December 31, 2018, and the related statements of income, members' equity, and cash flows for each of the two years in the period ended December 31, 2018.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on the financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Rockies Express Pipeline LLC as of December 31, 2018, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2018 in accordance with accounting principles generally accepted in the United States of America.

Emphasis of Matters

As described in Note 6 to the financial statements, the Company has significant transactions with related parties.

As discussed in Notes 2 and 7 to the financial statements, the Company changed the manner in which it accounts for revenue in 2018.

Our opinion is not modified with respect to these matters.

/s/ PricewaterhouseCoopers LLP

Denver, Colorado
February 8, 2019

ROCKIES EXPRESS PIPELINE LLC
BALANCE SHEETS

	December 31,	
	2019	2018
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	\$ 42.7	\$ 1.1
Accounts receivable, net.....	58.5	76.8
Gas imbalances	5.1	7.4
Current portion of contract asset	38.2	31.8
Other current assets	1.1	3.6
Total Current Assets.....	145.6	120.7
Property, plant and equipment, net.....	5,631.4	5,759.0
Contract asset	129.2	157.0
Right of use asset.....	184.3	—
Deferred charges and other assets	10.0	15.2
Total Noncurrent Assets.....	5,954.9	5,931.2
Total Assets.....	\$ 6,100.5	\$ 6,051.9
LIABILITIES AND EQUITY		
Current Liabilities:		
Accounts payable.....	\$ 9.6	\$ 21.0
Accrued interest.....	44.1	39.0
Accrued taxes	80.2	81.8
Current portion of long-term debt	—	525.0
Current portion of lease liability.....	18.5	—
Accrued other current liabilities	30.7	23.6
Total Current Liabilities.....	183.1	690.4
Long-term Liabilities and Deferred Credits:		
Long-term debt, net	2,036.6	1,492.7
Long term lease liability	165.8	—
Other long-term liabilities and deferred credits.....	9.1	10.2
Total Long-term Liabilities and Deferred Credits	2,211.5	1,502.9
Commitments and Contingencies		
Members' Equity:		
Members' equity	3,705.9	3,858.6
Total Liabilities and Members' Equity	\$ 6,100.5	\$ 6,051.9

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

ROCKIES EXPRESS PIPELINE LLC
STATEMENTS OF INCOME

	Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Revenues:			
Transportation services.....	\$ 893.3	\$ 907.7	\$ 839.6
Natural gas sales	2.3	6.9	9.6
Total Revenues.....	895.6	914.6	849.2
Operating Costs and Expenses:			
Cost of transportation services	28.9	32.3	29.8
Cost of natural gas sales	4.5	5.0	7.3
Operations and maintenance.....	28.7	27.0	25.3
Depreciation and amortization	220.4	219.6	218.4
General and administrative	30.4	28.2	30.5
Taxes, other than income taxes.....	101.2	85.3	65.3
Total Operating Costs and Expenses	414.1	397.4	376.6
Operating Income	481.5	517.2	472.6
Other (Expense) Income:			
Interest expense, net	(121.0)	(150.0)	(168.0)
Gain on litigation settlement	—	—	150.0
Other income, net	16.0	2.3	3.4
Total Other Expense, net.....	(105.0)	(147.7)	(14.6)
Net Income	\$ 376.5	\$ 369.5	\$ 458.0

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

ROCKIES EXPRESS PIPELINE LLC
STATEMENTS OF MEMBERS' EQUITY

	Total	Rockies Express Holdings, LLC	TEP REX Holdings, LLC	Phillips 66 Company
	(in millions)			
Members' Equity:				
Balance at January 1, 2017	\$ 3,430.0	\$ 1,715.0	\$ 857.5	\$ 857.5
Net Income.....	458.0	131.1	212.4	114.5
Contributions from Members	92.0	29.7	39.3	23.0
Distributions to Members	(669.9)	(197.6)	(304.8)	(167.5)
Transfer of equity interest (see Note 1)	—	(850.3)	850.3	—
Balance at December 31, 2017	\$ 3,310.1	\$ 827.9	\$ 1,654.7	\$ 827.5
Cumulative effect of ASC 606 implementation	125.2	51.0	42.9	31.3
Net Income.....	369.5	44.9	232.2	92.4
Contributions from Members	576.5	1.6	430.7	144.2
Distributions to Members	(522.7)	(63.7)	(328.4)	(130.6)
Transfer of equity interest (see Note 1)	—	(861.7)	861.7	—
Balance at December 31, 2018	\$ 3,858.6	\$ —	\$ 2,893.8	\$ 964.8
Net Income.....	376.5	—	282.4	94.1
Contributions from Members	82.9	—	62.2	20.7
Distributions to Members	(612.1)	—	(459.1)	(153.0)
Balance at December 31, 2019	\$ 3,705.9	\$ —	\$ 2,779.3	\$ 926.6

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

ROCKIES EXPRESS PIPELINE LLC
STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Cash Flows from Operating Activities:			
Net income.....	\$ 376.5	\$ 369.5	\$ 458.0
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization.....	222.8	224.7	223.7
Change in contract asset	21.4	(62.3)	—
Noncash lease expense	17.3	—	—
Other noncash items, net.....	3.4	—	—
Changes in components of working capital:			
Accounts receivable.....	18.4	(1.7)	(25.4)
Lease liability.....	(17.3)	—	—
Accounts payable and accrued other current liabilities	(2.8)	(19.6)	(7.0)
Accrued taxes.....	8.7	11.4	(7.6)
Other current assets and liabilities	—	7.2	3.4
Return of customer deposits	(3.0)	(29.9)	(55.7)
Receipt of customer deposits.....	2.3	8.4	5.8
Other operating, net	(4.2)	3.9	1.1
Net Cash Provided by Operating Activities	643.5	511.6	596.3
Cash Flows from Investing Activities:			
Capital expenditures	(86.6)	(36.5)	(108.9)
Other investing, net	(2.3)	(3.3)	(2.2)
Net Cash Used in Investing Activities.....	(88.9)	(39.8)	(111.1)
Cash Flows from Financing Activities:			
Distributions to Members	(612.1)	(522.7)	(669.9)
Proceeds from issuance of Senior Notes	549.0	—	—
Repayment of Senior Notes.....	(525.0)	(550.0)	—
Proceeds from issuance of Term Loan	525.0	—	—
Repayment of Term Loan	(525.0)	—	—
Contributions from Members	82.9	576.5	92.0
Other financing, net	(7.8)	(0.2)	—
Net Cash Used in Financing Activities	(513.0)	(496.4)	(577.9)
Net Change in Cash and Cash Equivalents	41.6	(24.6)	(92.7)
Cash and Cash Equivalents, beginning of period.....	1.1	25.7	118.4
Cash and Cash Equivalents, end of period.....	\$ 42.7	\$ 1.1	\$ 25.7
Supplemental Disclosures:			
Cash payments for interest, net	\$ (114.4)	\$ (164.9)	\$ (164.9)
Schedule of Noncash Investing and Financing Activities:			
Accruals for payment of property, plant and equipment	\$ 6.8	\$ 2.8	\$ —

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

ROCKIES EXPRESS PIPELINE LLC

NOTES TO FINANCIAL STATEMENTS

1. Description of Business

Rockies Express Pipeline LLC ("Rockies Express") is a Federal Energy Regulatory Commission ("FERC") regulated natural gas transportation system with approximately 1,712 miles of natural gas pipeline, including laterals, extending from Opal, Wyoming and Meeker, Colorado to Clarington, Ohio and consisting of three zones:

- Zone 1 - a 328-mile pipeline from the Meeker Hub in Northwest Colorado, across Southern Wyoming to the Cheyenne Hub in Weld County, Colorado capable of transporting 2.0 Bcf/d of natural gas from west to east;
- Zone 2 - a 714-mile pipeline from the Cheyenne Hub to an interconnect in Audrain County, Missouri capable of transporting 1.8 Bcf/d of natural gas from west to east; and
- Zone 3 - a 643-mile pipeline from Audrain County, Missouri to Clarington, Ohio, which is bi-directional and capable of transporting 1.8 Bcf/d of natural gas from west to east and 2.6 Bcf/d of natural gas from east to west.

The member interests and voting rights in Rockies Express as of December 31, 2019 are as follows:

- 75% - TEP REX Holdings, LLC ("TEP REX"), an indirect subsidiary of Tallgrass Energy, LP ("TGE"); and
- 25% - Phillips 66 Company, a wholly owned subsidiary of Phillips 66 and successor by merger to P66REX LLC.

On March 31, 2017, Tallgrass Energy Partners, LP ("TEP"), Tallgrass Development LP ("TD"), and Rockies Express Holdings, LLC ("REX Holdings"), an indirect wholly owned subsidiary of TD, entered into a definitive Purchase and Sale Agreement, pursuant to which TEP acquired an additional 24.99% membership interest in Rockies Express from TD in exchange for cash consideration of \$400 million. This transaction increased TEP REX's aggregate membership interest in Rockies Express to 49.99%.

On February 7, 2018, Tallgrass Development Holdings, LLC ("Tallgrass Development Holdings"), a wholly owned subsidiary of Tallgrass Equity, acquired REX Holdings and its 25.01% membership interest in Rockies Express as a result of the merger of TD into Tallgrass Development Holdings. Tallgrass Equity is the sole member of TEP's general partner. Effective July 1, 2018, REX Holdings was merged into TEP REX, resulting in TEP REX owning a 75% membership interest in Rockies Express.

2. Summary of Significant Accounting Policies

Basis of Presentation

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities, and the reported amounts of revenues and expenses. Actual results could differ from these estimates. Certain prior year amounts have been reclassified to conform to the current presentation.

Rockies Express has no elements of other comprehensive income for the periods presented.

Use of Estimates

Certain amounts included in or affecting these 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.

Cash and Cash Equivalents

Rockies Express considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are carried at their estimated collectible amounts. Rockies Express periodically reviews and evaluates the appropriateness of the allowance for doubtful accounts based on a statistical analysis of historical defaults, and adjustments are recorded as necessary for changes in circumstances and customer-specific information. When specific receivables are

determined to be uncollectible, the reserve and receivable are relieved. Our allowance for doubtful accounts totaled \$1.0 million at December 31, 2019 and 2018.

Fuel Recovery Mechanism

Rockies Express obtains natural gas quantities from its shippers as reimbursement for fuel consumed at compressor stations and other locations on its system as well as for natural gas quantities lost and otherwise unaccounted for, in accordance with its tariff and applicable contract terms. Rockies Express tracks the volume and value of associated over- or under-collections of fuel and lost and unaccounted for quantities through a tracking mechanism referred to as "fuel tracker." Those amounts are recorded as an addition or reduction to a regulatory asset or liability balance representing the amounts to be recovered from or refunded to customers through the fuel tracker mechanisms. Fuel tracker volumes are valued using a weighted-average monthly index price.

Accounting for Regulatory Activities

Rockies Express' regulated activities are accounted for in accordance with the "Regulated Operations" Topic of the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("Codification"). This Topic prescribes the circumstances in which the application of GAAP is affected by the economic effects of regulation. Regulatory assets and liabilities represent probable future revenues or expenses to Rockies Express associated with certain charges and credits that will be recovered from or refunded to customers through the ratemaking process. Rockies Express recorded regulatory assets of approximately \$1.2 million and \$0.7 million at December 31, 2019 and 2018, respectively, and regulatory liabilities of approximately \$3.7 million and \$1.8 million at December 31, 2019 and 2018, respectively, primarily attributable to the fuel tracker discussed in "Fuel Recovery Mechanism" above.

Gas Imbalances

Gas imbalances receivable and payable reflect gas volumes owed between Rockies Express and its customers. Gas imbalances represent the difference between customer nominated versus actual gas receipts from and gas deliveries to interconnecting pipelines under various operational balancing agreements. Gas imbalances are settled in cash or made up in-kind subject to the terms of the various agreements and are valued at the average monthly index price.

Property, Plant and Equipment

Property, plant and equipment is stated at historical cost, which for constructed assets includes indirect costs such as payroll taxes, other employee benefits, allowance for funds used during construction and other costs directly related to the projects. Expenditures that increase capacities, improve efficiencies or extend useful lives are capitalized and depreciated over the remaining useful life of the asset or major asset component. Rockies Express also capitalizes certain costs directly related to the construction of assets, including internal labor costs, interest and engineering costs.

Routine maintenance, repairs and renewal costs are expensed as incurred. The cost of normal retirements of depreciable utility property, plant and equipment, plus the cost of removal less salvage value and any gain or loss recognized, is recorded in accumulated depreciation with no effect on current period earnings. Gains or losses are recognized upon retirement of property, plant and equipment constituting an operating unit or system, and land, when sold or abandoned and costs of removal or salvage are expensed when incurred.

Rockies Express maintains natural gas in its pipeline, known as "line pack," which serves to maintain the necessary pressure to allow efficient transmission of natural gas. Line pack is capitalized within "Property, plant and equipment, net" on the balance sheets and depreciated over the estimated useful life of the pipeline.

Impairment of Long-Lived Assets

Rockies Express reviews its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. An impairment loss results when the estimated undiscounted future net cash flows expected to result from the asset's use and its eventual disposition are less than its carrying amount. Rockies Express assesses its long-lived assets for impairment in accordance with the relevant Codification guidance. A long-lived asset is tested for impairment whenever events or changes in circumstances indicate its carrying amount may exceed its fair value.

Examples of long-lived asset impairment indicators include:

- a significant decrease in the market value of a long-lived asset or group;
- a significant adverse change in the extent or manner in which a long-lived asset or asset group is being used or in its physical condition;
- a significant adverse change in legal factors or in the business climate could affect the value of a long-lived asset or asset group, including an adverse action or assessment by a regulator which would exclude allowable costs from the rate-making process;

- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of the long-lived asset or asset group;
- a current period operating cash flow loss combined with a history of operating cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset or asset group; and
- a current expectation that, more likely than not, a long-lived asset or asset group will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.

When an impairment indicator is present, Rockies Express first assesses the recoverability of the long-lived assets by comparing the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset to the carrying amount of the asset. If the carrying amount is higher than the undiscounted future cash flows, the fair value of the asset is assessed using a discounted cash flow analysis to determine the amount of impairment, if any, to be recognized.

Depreciation and Amortization

Rockies Express has elected to compute depreciation using a composite method employed by applying a single depreciation rate to a group of assets with similar economic characteristics. The annual composite rate of depreciation for the years ended December 31, 2019, 2018, and 2017 was 2.86%.

Allowance for Funds Used During Construction

Included in the cost of "Property, plant and equipment, net" on the accompanying balance sheets is an allowance for funds used during construction ("AFUDC"). AFUDC represents the estimated cost of debt, from borrowed funds, or the estimated cost of capital, from equity funds, during the construction period. During the years ended December 31, 2019, 2018 and 2017 Rockies Express recognized AFUDC associated with the estimated cost of debt of approximately \$1.7 million, \$0.3 million, and \$0.2 million, respectively, recorded as "Interest expense, net" on the accompanying statements of income. During the years ended December 31, 2019, 2018, and 2017, Rockies Express recognized AFUDC associated with the estimated cost of capital from equity funds of approximately \$2.7 million, \$0.6 million, and \$0.5 million, respectively, recorded as "Other income, net" on the accompanying statements of income.

Revenue Recognition

Rockies Express adopted Accounting Standards Update ("ASU") No. 2014-09, "Revenue from Contracts with Customers" on January 1, 2018, using the modified retrospective method. For periods subsequent to adoption, Rockies Express accounts for revenue from contracts with customers in accordance with the five-step model outlined in ASC Topic 606, *"Revenue from Contracts with Customers"* ("ASC 606"). Under the five-step model, Rockies Express identifies the contract, identifies the performance obligations, determines the transaction price, allocates the transaction price, and recognizes revenue. Revenue is recognized when (or as) the performance obligations are satisfied. For additional information see Note 7 – *Revenue from Contracts with Customers*.

Deferred Financing Costs

Costs incurred in connection with the issuance of long-term debt are deferred and amortized over the related financing period using the effective interest method. Deferred financing costs associated with long-term debt are presented as a reduction to the corresponding debt on the accompanying balance sheets. Deferred financing costs associated with revolving credit facilities or lines of credit are classified as noncurrent assets on the accompanying balance sheets. During the year ended December 31, 2019, Rockies Express recognized a \$0.5 million loss on debt retirement, recorded as "Other income, net" in the accompanying statements of income, associated with the write off of deferred financing costs associated with the Term Loan and the Amendment and Restatement to the Rockies Express revolving credit facility as discussed further in Note 4 – *Financing*.

Deferred Charges and Deferred Credits

Rockies Express has no remaining balance left of an initial \$20.0 million deferred charge and deferred credit relating to a customer contract. The deferred charge was being amortized using a straight-line-method over the life of the related contract. Amortization of the deferred charge for each of the years ended December 31, 2019, 2018, and 2017 was \$0.5 million, \$2.0 million, and \$2.0 million and is included within transportation services revenues in the accompanying statements of income. The deferred credit was payable over a period of 10 years.

Environmental Matters

Rockies Express expenses or capitalizes, as appropriate, environmental expenditures that relate to current operations. Rockies Express expenses amounts that relate to an existing condition caused by past operations that do not contribute to current or future revenue generation. Rockies Express does not discount environmental liabilities to a net present value, and records environmental liabilities when environmental assessments and/or remedial efforts are probable and costs can be

reasonably estimated. Generally, recording of these accruals coincides with the completion of a feasibility study or a commitment to a formal plan of action.

Fair Value

Fair value, as defined in the fair value measurement accounting guidance, is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, or exit price. The fair value measurement accounting guidance requires that Rockies Express make assumptions that market participants would use in pricing an asset or liability based on the best information available. These factors include nonperformance risk (the risk that an obligation will not be fulfilled) and credit risk of the reporting entity (for liabilities) and of the counterparty (for assets). The fair value measurement guidance prohibits the inclusion of transaction costs and any adjustments for blockage factors in determining the instruments' fair value. The principal or most advantageous market should be considered from the perspective of the reporting entity. The fair value of current financial assets and liabilities approximate their reported carrying amounts as of December 31, 2019 and 2018.

Income Taxes

Rockies Express is a limited liability company that has elected to be treated as a partnership for income tax purposes. Accordingly, no provision for federal or state income taxes has been recorded in the financial statements of Rockies Express and the tax effects of Rockies Express' activities accrue to its Members.

Accounting Pronouncement Recently Adopted

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

In February 2016, the Financial Accounting Standards Board ("FASB") issued ASU No. 2016-02, Leases (Topic 842). ASU 2016-02 provides a comprehensive update to the lease accounting topic within GAAP intended to increase transparency and comparability among organizations by recognizing right-of-use ("ROU") 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 has completed its evaluation and implemented the revised guidance using the modified retrospective method as of January 1, 2019. This approach allows Rockies Express to (i) initially apply ASC 842 at the adoption date, January 1, 2019 and (ii) continue reporting comparative periods presented in the financial statements in the period of adoption under the previous guidance. Accordingly, Rockies Express will not recast comparative periods in the accompanying financial statements. Management elected the package of practical expedients permitted under the transition guidance within the new standard, which among other things, allowed Rockies Express to carry forward the historical lease classification. Management has also elected the following practical expedients: (a) the land easement practical expedient, allowing Rockies Express to carry forward the accounting treatment for existing land easements as property, plant and equipment, (b) the practical expedient for short-term leases, allowing Rockies Express to not recognize ROU assets or lease liabilities for leases with a term of 12 months or less, and (c) for agreements that contain both lease and non-lease components, combining these components together and accounting for them as a single lease.

Adoption of the new standard resulted in the recognition of ROU assets of approximately \$201.6 million, and current and non-current lease liabilities of approximately \$17.4 million and \$184.2 million, respectively, for operating leases as of January 1, 2019. The adoption of this guidance had no impact to our cash flows from operating, investing, or financing activities. For additional information see Note 8 – *Leases*.

Accounting Pronouncements Not Yet Adopted

ASU No. 2016-13, "Financial Instruments–Credit Losses (Topic 326)"

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments–Credit Losses (Topic 326). ASU 2016-13 amends current measurement techniques used to estimate credit losses for financial assets. The amendments in ASU 2016-13 are effective for public business entities' financial statements issued for annual periods beginning after December 15, 2019, and interim periods within those annual periods. Early adoption is permitted. Rockies Express continues to evaluate the impact of ASU 2016-13, but does not currently expect the adoption to have a material impact.

3. Property, Plant and Equipment

Rockies Express' property, plant and equipment, net consisted of the following:

	December 31,	
	2019	2018
	(in millions)	
Natural gas pipelines	\$ 7,710.3	\$ 7,677.0
General and other	16.3	15.8
Construction work in progress	79.6	27.8
Accumulated depreciation and amortization	(2,174.8)	(1,961.6)
Total property, plant and equipment, net	<u>\$ 5,631.4</u>	<u>\$ 5,759.0</u>

Depreciation expense was approximately \$220.4 million, \$219.6 million and \$218.4 million for the years ended December 31, 2019, 2018 and 2017, respectively.

4. Financing

Debt

Total outstanding debt as of December 31, 2019 and 2018 consisted of the following:

	December 31,	
	2019	2018
	(in millions)	
6.00% senior notes due January 15, 2019	\$ —	\$ 525.0
5.625% senior notes due April 15, 2020 ⁽¹⁾	750.0	750.0
4.95% senior notes due July 15, 2029	550.0	—
7.50% senior notes due July 15, 2038	250.0	250.0
6.875% senior notes due April 15, 2040	500.0	500.0
Less: Unamortized debt discount and deferred financing costs ⁽²⁾	(13.4)	(7.3)
Total debt, net	<u>2,036.6</u>	<u>2,017.7</u>
Less: Current portion	—	(525.0)
Total long-term debt, net	<u>\$ 2,036.6</u>	<u>\$ 1,492.7</u>

⁽¹⁾ As discussed further below, Rockies Express issued an additional \$750.0 million of senior notes on January 31, 2020, the proceeds of which will be used to redeem the \$750.0 million of senior notes due April 15, 2020 in March 2020.

⁽²⁾ Deferred financing costs as presented above relate to the Senior Notes. Deferred financing costs associated with Rockies Express revolving credit facility are presented in noncurrent assets in the accompanying balance sheets.

Rockies Express Senior Notes

The senior notes issued by Rockies Express are redeemable in whole or in part, at Rockies Express' option at any time, at redemption prices defined in the associated indenture agreements.

All payments of principal and interest with respect to the fixed rate senior notes are the sole obligation of Rockies Express. Note holders have no recourse against Rockies Express' Members or their respective officers, directors, employees, shareholders, members, managers, unit holders or affiliates for any failure by Rockies Express to perform or comply with its obligations pursuant to the notes or the indenture. As of December 31, 2019, Rockies Express was in compliance with the covenants required under the senior notes.

On January 31, 2020, Rockies Express issued \$750 million in aggregate principal amount of senior notes. The issuance was composed of two tranches, \$400 million of 3.60% senior notes due 2025 and \$350 million of 4.80% senior notes due 2030. The proceeds of the issuance will be used to redeem Rockies Express' existing 5.625% senior notes due April 15, 2020 in March 2020.

The 6.00% senior notes were repaid on January 15, 2019. The repayment was funded by the issuance of a 364-Day Term Loan Agreement effective January 8, 2019 (the "Term Loan") with a maturity date of January 7, 2020. On April 12, 2019,

Rockies Express issued \$550 million in aggregate principal amount of 4.95% senior notes due 2029. Substantially all of the net proceeds received from the senior notes offering were used to repay the Term Loan.

On July 15, 2018, Rockies Express repaid \$550 million of 6.85% senior notes due July 15, 2018. The repayment was funded by contributions from the Rockies Express Members.

Maturities of Debt

The scheduled maturities of Rockies Express' outstanding debt balances as of December 31, 2019 are summarized as follows (in millions):

Year	Scheduled Maturities
2020.....	\$ —
2021.....	—
2022.....	—
2023.....	—
2024.....	—
Thereafter ⁽¹⁾	2,050.0
Total scheduled maturities.....	2,050.0
Unamortized debt discount and deferred financing costs	(13.4)
Total debt.....	<u>\$ 2,036.6</u>

⁽¹⁾ As discussed further above, Rockies Express issued an additional \$750.0 million of senior notes on January 31, 2020, the proceeds of which will be used to redeem the \$750.0 million of senior notes due April 15, 2020 in March 2020.

Rockies Express Revolving Credit Facility

On November 18, 2019, Rockies Express entered into an amendment and restatement (the "Amendment and Restatement") of its existing \$150 million senior unsecured revolving credit facility ("the revolving credit facility") with Wells Fargo Bank, N.A., as administrative agent, and a syndicate of lenders. The Amendment and Restatement, among other things, extended the maturity date of the revolving credit facility from January 31, 2020 to November 18, 2024 and reduced certain of the applicable margins and commitment fee rates in the pricing grid used to determine the interest rate and commitment fee. The revolving credit facility includes a \$75 million sublimit for letters of credit and a \$20 million sublimit for swing line loans and may be used for working capital and general company purposes. The revolving credit facility also contains an accordion feature whereby Rockies Express can increase the size of the credit facility to an aggregate of \$200 million, subject to receiving increased or new commitments from lenders and the satisfaction of certain other conditions precedent. As of December 31, 2019, there were no outstanding borrowings or letters of credit issued under the revolving credit facility.

Borrowings under the revolving credit facility bear interest, at Rockies Express' 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 0.375% to 1.125% for base rate borrowings and 1.375% to 2.125% for reserve adjusted Eurodollar rate borrowings, based upon Rockies Express' total leverage ratio. The unused portion of the revolving credit facility is subject to a commitment fee, which ranges from 0.20% to 0.40% based upon Rockies Express' total leverage ratio.

Rockies Express has the option to have the applicable margin determined based on Rockies Express' credit ratings. If Rockies Express were to make an election to exercise this option, the applicable margin would range from 0.125% to 0.75% for base rate borrowings and 1.125% to 1.750% for reserve adjusted Eurodollar borrowings, based on Rockies Express' credit ratings. Under such an election, the commitment fee would range from 0.125% to 0.25%, also based on Rockies Express' credit ratings.

Covenants Under the Revolving Credit Facility

The revolving credit facility generally requires Rockies Express to comply with various affirmative and negative covenants, including a limit on the leverage ratio (as defined in the credit agreement) of Rockies Express and restrictions on:

- incurring secured indebtedness;
- entering into mergers, consolidations and sales of assets;
- granting liens;
- entering into transactions with affiliates; and

- making restricted payments.

As of December 31, 2019, Rockies Express was in compliance with the covenants required under the revolving credit facility.

Fair Value

The following table sets forth the carrying amount and fair value of Rockies Express' debt, which is not measured at fair value in the accompanying balance sheets as of December 31, 2019 and 2018, but for which fair value is disclosed:

	Fair Value					Carrying Amount
	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total		
	(in millions)					
December 31, 2019	\$ —	\$ 2,096.9	\$ —	\$ 2,096.9	\$ 2,036.6	
December 31, 2018	\$ —	\$ 2,086.9	\$ —	\$ 2,086.9	\$ 2,017.7	

The debt is carried at amortized cost, net of deferred financing costs. The estimated fair value of Rockies Express' outstanding private placement debt is based upon quoted market prices adjusted for illiquid markets. Rockies Express is not aware of any factors that would significantly affect the estimated fair value subsequent to December 31, 2019.

5. Members' Equity

During the years ended December 31, 2019, 2018, and 2017, Rockies Express made distributions to Members of \$612.1 million, \$522.7 million, and \$669.9 million, respectively. The distributions paid by Rockies Express during the year ended December 31, 2017 included a distribution of the proceeds from the Ultra settlement discussed in Note 12 – *Legal and Environmental Matters*.

During the years ended December 31, 2019, 2018, and 2017, Rockies Express received contributions from Members of \$82.9 million, \$576.5 million, and \$92.0 million, respectively. Contributions from Members during the year ended December 31, 2019 were primarily used to fund the construction and other costs of the Cheyenne Hub Enhancement project, as discussed in Note 11 – *Regulatory Matters*. Contributions from Members during the year ended December 31, 2018 included a special contribution of approximately \$550 million to fund the repayment of senior notes as discussed in Note 4 – *Financing*. Contributions from Members during the year ended December 31, 2017 were primarily used to fund the construction and other costs of the Zone 3 Capacity Enhancement project, as discussed in Note 11 – *Regulatory Matters*.

Additional contributions and distributions were made subsequent to December 31, 2019. For details see Note 13 – *Subsequent Events*.

6. Related Party Transactions

Rockies Express has an operating agreement with Tallgrass NatGas Operator, LLC ("NatGas"), an indirect subsidiary of TGE, under which NatGas provides and bills Rockies Express for various services at cost including employee labor costs, information technology services, employee health and retirement benefits, and insurance for property and casualty risks. In addition, NatGas receives a management oversight fee in the amount of 1% of Rockies Express' earnings before interest, taxes, depreciation, and amortization. Rockies Express' practice is to settle receivable and payable balances that exist with affiliates in the following month.

Totals of significant transactions with affiliated companies are as follows:

	Years Ended December 31,					
	2019		2018		2017	
	(in millions)					
Charges to Rockies Express:						
Property, plant, and equipment, net	\$	1.1	\$	1.2	\$	1.4
Operations and maintenance		10.0		9.7		10.0
General and administrative		19.1		17.5		16.0
Management Fees:						
General and administrative	\$	7.4	\$	7.5	\$	8.5

Balances with affiliated companies included in the accompanying balance sheets include amounts payable to TGE of \$4.0 million and \$3.4 million as of December 31, 2019 and December 31, 2018, respectively. Gas imbalances with affiliated shippers in the accompanying balance sheets include amounts receivable of \$0.9 million and \$0.8 million as of December 31, 2019 and December 31, 2018, respectively.

7. Revenue from Contracts with Customers

Disaggregated Revenue

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

	Year Ended December 31,	
	2019	2018
	(in millions)	
Firm Transportation - West to East	\$ 435.9	\$ 467.7
Firm Transportation - East to West	440.7	425.0
All other	16.7	15.0
Total transportation services revenue	893.3	907.7
Natural gas sales	2.3	6.9
Total revenue	\$ 895.6	\$ 914.6

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 Rockies Express' contracts have a single performance obligation and are billed and collected monthly. These performance obligations typically include an obligation to stand ready to provide natural gas transportation 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.

Rockies Express also engages in commodity sales, in which the 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.

On December 31, 2019, Rockies Express had \$6.7 billion of remaining performance obligations, which Rockies Express refers to as total backlog. Total backlog includes performance obligations under firm transportation contracts and excludes variable consideration that is not estimated at contract inception, as discussed further below. Rockies Express expects to recognize the total backlog during future periods as follows (in millions):

Year	Estimated Revenue
2020.....	\$ 630.7
2021.....	615.9
2022.....	579.2
2023.....	572.6
2024.....	494.9
Thereafter.....	3,770.3
Total.....	<u>\$ 6,663.6</u>

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.

The nature of our contracts gives rise to several types of variable consideration, including 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 and the uncertainty related to the consideration is resolved each month as the distinct service is provided, Rockies Express does not estimate the total variable consideration for the single overall performance obligation. Consequently, Rockies Express is 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.

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 balance sheets. Revenue is generally billed and collected monthly based on services provided or volumes sold. As of December 31, 2019, December 31, 2018, and January 1, 2018 the contract asset balance was \$167.4 million, \$188.8 million, and \$131.7 million, respectively, which represents the difference between the revenue recognized and the actual cash collected from certain contracts with rates that vary throughout the term of the contract.

8. Leases

Rockies Express accounts for leases in accordance with ASC Topic 842, Leases, which was adopted on January 1, 2019, applying the modified retrospective transition approach as of the effective date of adoption. See Note 2 – *Summary of Significant Accounting Policies* for additional information regarding the impacts of adoption.

Under ASC 842, a contract is or contains a lease when, (1) the contract contains an explicitly or implicitly identified asset and (2) the customer obtains substantially all of the economic benefits from the use of that underlying asset and directs how and for what purpose the asset is used during the term of the contract in exchange for consideration. Rockies Express assesses whether an arrangement is or contains a lease at inception of the contract. For all leases (finance and operating leases), other than those that qualify for the short-term recognition exemption, Rockies Express recognizes as of the lease commencement date on the balance sheet a liability for our obligation related to the lease and a corresponding asset representing our right to use the underlying asset over the period of use. The discount rate used to calculate the present value of the future minimum lease payments is the rate implicit in the lease, when readily determinable. As our leases do not provide an implicit rate, Rockies Express determines the appropriate discount rate using our incremental secured borrowing rate, with consideration given to the nature and term of the leased asset.

For the years ended December 31, 2019, 2018, and 2017 operating lease cost was \$29.1 million, \$29.2 million, and \$29.2 million, respectively. For the year ended December 31, 2019 cash paid included in operating cash flows was \$29.1 million. As of December 31, 2019, the weighted average remaining lease term for operating leases was 8.0 years and the weighted average discount rate for operating leases was 6.05%.

Maturities of lease liabilities as of December 31, 2019 were as follows (in millions):

Year	Operating Leases
2020	\$ 29.1
2021	29.1
2022	29.1
2023	29.1
2024	29.1
Thereafter	87.3
Total lease payments	232.8
Less: discounting for present value and other adjustments	(48.5)
Present value of lease liabilities	<u>\$ 184.3</u>

The future minimum rental commitments are primarily attributable to a 20-year capacity lease agreement with Overthrust Pipeline Company ("Overthrust") which commenced on January 1, 2008. The capacity lease provides the right to transport on a firm basis 625 MMcf/d of natural gas through Overthrust's system from either the Williams Field Services Opal Processing Plant or the TEPPCO Pioneer Processing Plant to the Wamsutter interconnect.

Information as of December 31, 2018 under historical lease accounting guidance:

At December 31, 2018, our future minimum rental commitments under major, non-cancelable leases were as follows (in millions):

Year	Operating Leases
2019	\$ 29.1
2020	29.1
2021	29.1
2022	29.1
2023	29.1
Thereafter	116.4
Total	<u>\$ 261.9</u>

9. Commitments and Contingent Liabilities

Capital Expenditures

Approximately \$32.7 million of Rockies Express' capital expenditure budget for 2020 had been committed for purchases of property, plant and equipment at December 31, 2019.

10. Major Customers

During 2019, four non-affiliated shippers accounted for \$145.0 million (16%), \$142.1 million (16%), \$116.3 million (13%), and \$112.2 million (13%), respectively of Rockies Express' total revenues. During 2018, three non-affiliated shippers accounted for \$168.5 million (18%), \$118.7 million (13%), and \$112.2 million (12%), respectively of Rockies Express' total revenues. During 2017, three non-affiliated shippers accounted for \$169.4 million (20%), \$111.9 million (13%), and \$101.3 million (12%), respectively of Rockies Express' total revenues. Rockies Express attempts to mitigate credit risk by seeking collateral or financial guarantees and letters of credit from customers.

11. Regulatory Matters

Ratemaking Process

Transportation and storage services on interstate natural gas pipelines are contracted under one of three rate types: recourse, discount, or negotiated. Recourse rates are calculated based on the cost of service being provided and include an allowable rate of return for the pipeline. Recourse rates are established through a FERC rate proceeding and remain effective until a subsequent rate proceeding is filed and approved by the FERC. Discount rates are offered at a discount to the then-effective maximum recourse rate. Discount rates are typically effective for an established term and can vary based on movement of the underlying recourse rate. Negotiated rates can be higher or lower than the then-effective maximum recourse

rate, subject to agreement between the pipeline and shipper and approval by the FERC. Negotiated rates are also entered into for a defined term but do not change based on adjustments in the applicable recourse rate for that type of service.

The majority of services provided by Rockies Express are contracted under negotiated rate agreements. Currently, there are no regulatory proceedings challenging the transportation rates of Rockies Express.

Other Regulatory Matters

Rockies Express has made certain regulatory filings with the FERC, including those further described below:

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.

Rockies Express Cheyenne Hub Enhancement Project - FERC Docket No. CP18-103-000

On March 2, 2018, Rockies Express submitted an application pursuant to section 7(c) of the National 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 for the Cheyenne Connector Pipeline. On December 18, 2018, the FERC issued the Environmental Assessment. On September 20, 2019, the FERC issued an order approving the application. A notice to proceed with construction was issued on October 8, 2019.

12. Legal and Environmental Matters

Legal

In addition to the matters discussed below, Rockies Express is involved in various lawsuits arising from the day-to-day operations of its business. Although no assurance can be given, Rockies Express believes, based on its experiences to date, that the ultimate resolution of such matters will not have a material adverse impact on its business, financial position, results of operations, or cash flows.

Rockies Express has evaluated claims in accordance with the accounting guidance for contingencies that it deems both probable and reasonably estimable and, accordingly, has recorded no reserve for legal claims as of December 31, 2019 or 2018.

EM Energy Ohio, LLC

On May 15, 2019, EM Energy Ohio, LLC ("EM Energy") and certain of its affiliates filed for protection under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware. EM Energy had a firm transportation service agreement with Rockies Express for 50,000 Dth/d through January 5, 2032. Rockies Express and EM Energy have stipulated in the bankruptcy proceeding that the termination date of the transportation service agreement is June 13, 2019. Following the termination, Rockies Express made a drawing equal to the outstanding face amount on the letter of credit supporting EM Energy's obligations under the transportation service agreement and received approximately \$16.2 million in June 2019. A portion of the proceeds was used to settle outstanding accounts receivable for transportation services provided to EM Energy and the remaining \$13.9 million was recognized as income by Rockies Express. Rockies Express intends to pursue its claim against the bankruptcy estate of EM Energy for damages and to remarket the capacity resulting from the termination of the transportation service agreement.

Ohio Public Utility Excise Tax

The Ohio Tax Commissioner has assessed Rockies Express a public utility excise tax on transactions concerning product that entered and exited the Rockies Express Pipeline within the State of Ohio. This tax applies to gross receipts from all business conducted within the state, but exempts all receipts derived wholly from interstate business. Rockies Express disputed its obligation to pay Ohio's public utility excise tax under the relevant Ohio statute, but made payments in the amounts assessed in order to preserve its right to appeal. On February 11, 2020, the Ohio Supreme Court reached a final decision adverse to the position taken by Rockies Express.

As a result of this decision, Rockies Express no longer believes that the refund of prior payments is probable and accordingly has recognized expense totaling \$15.8 million during the year ended December 31, 2019. The expense recognized represents total payments made to date to the state of Ohio of \$12.3 million and an additional \$3.5 million for amounts expected to be assessed for the period from May 1, 2019 through December 31, 2019 and has been recorded as "Taxes, other than income taxes" in Rockies Express' statements of income.

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.

Michels Corporation

On June 17, 2014, Michels Corporation ("Michels") filed a complaint and request for relief against Rockies Express in the Court of Common Pleas, Monroe County, Ohio, as a result of work performed by Michels to construct the Seneca Lateral Pipeline in Ohio. Michels sought unspecified damages from Rockies Express and asserted claims of breach of contract, negligent misrepresentation, unjust enrichment and quantum meruit. Michels also filed notices of Mechanic's Liens in Monroe and Noble Counties, asserting \$24.2 million as the amount due.

On February 2, 2017, Rockies Express and Michels agreed to resolve Michels' claims for a \$10 million cash payment by Rockies Express. The cash payment was inclusive of approximately \$5.9 million that Rockies Express had been withholding from Michels. Subsequently, Rockies Express and Michels entered into a definitive agreement with respect to the settlement and Rockies Express made the \$10 million cash payment to Michels on February 16, 2017.

Environmental, Health and Safety

Rockies Express is subject to a variety of federal, state and local laws that regulate permitted activities relating to air and water quality, waste disposal, and other environmental matters. Rockies Express currently believes that compliance with these laws will not have a material adverse impact on its business, cash flows, financial position or results of operations. However, there can be no assurances that future events, such as changes in existing laws, the promulgation of new laws, or the development of new facts or conditions will not cause Rockies Express to incur significant costs.

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. Permanent repairs were completed in September 2018. Total cost of remediation was approximately \$6.1 million, \$5.1 million of which Rockies Express has recovered through insurance.

13. Subsequent Events

Subsequent events, which are events or transactions that occurred after December 31, 2019 through the issuance of the accompanying financial statements, have been evaluated through February 12, 2020.

Members' Equity

Rockies Express paid distributions of \$39.1 million to its Members and received contributions from its Members of \$5.8 million in January 2019.

(2) Financial Statement Schedules

All schedules are omitted because they are either not applicable or the required information is shown in the Consolidated Financial Statements or notes thereto included in Item 8 of this Form 10-K.

(3) Exhibits

Exhibit No.	Description
<u>2.1</u>	<u>Agreement and Plan of Merger, dated as of February 7, 2018, by and among Tallgrass Energy GP, LP, Tallgrass Development, LP, Tallgrass Equity, LLC, Tallgrass Development Holdings, LLC and Tallgrass Energy Holdings, LLC (incorporated by reference to Exhibit 2.2 to Tallgrass Energy, LP's Quarterly Report on Form 10-Q filed on May 3, 2018).</u>
<u>2.2</u>	<u>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, LP's Current Report on Form 8-K filed on March 27, 2018).</u>
<u>2.3</u>	<u>Agreement and Plan of Merger, dated as of December 16, 2019, by and among Tallgrass Energy, LP, Tallgrass Energy GP, LLC, Prairie Private Acquiror LP and Prairie Merger Sub LLC (incorporated by reference to Exhibit 2.1 to Tallgrass Energy, LP's Current Report on Form 8-K filed on December 17, 2019).</u>
<u>3.1</u>	<u>Certificate of Limited Partnership of Tallgrass Energy GP, LP, dated February 10, 2015 (now known as Tallgrass Energy, LP) (incorporated by reference to Exhibit 3.1 to Tallgrass Energy GP, LP's Registration Statement on Form S-1 filed February 24, 2015).</u>
<u>3.2</u>	<u>Certificate of Amendment to Certificate of Limited Partnership of Tallgrass Energy GP, LP, dated June 29, 2018 (now known as Tallgrass Energy, LP) (incorporated by reference to Exhibit 3.2 to Tallgrass Energy, LP's Current Report on Form 8-K filed on July 2, 2018).</u>
<u>3.3</u>	<u>Second Amended and Restated Agreement of Limited Partnership of Tallgrass Energy, LP, dated July 1, 2018 (incorporated by reference to Exhibit 3.3 to Tallgrass Energy, LP's Current Report on Form 8-K filed on July 2, 2018).</u>
<u>3.4</u>	<u>Certificate of Formation of TEGP Management, LLC, dated February 10, 2015 (now known as Tallgrass Energy GP, LLC) (incorporated by reference to Exhibit 3.3 to Tallgrass Energy GP, LP's Registration Statement on Form S-1 filed February 24, 2015).</u>
<u>3.5</u>	<u>Certificate of Amendment to Limited Liability Company Certificate of Formation of TEGP Management, LLC, dated June 29, 2018 (now known as Tallgrass Energy GP, LLC) (incorporated by reference to Exhibit 3.1 to Tallgrass Energy, LP's Current Report on Form 8-K filed on July 2, 2018).</u>
<u>3.6</u>	<u>Third Amended and Restated Limited Liability Company Agreement of Tallgrass Energy GP, LLC, dated March 11, 2019 (incorporated by reference to Exhibit 3.1 to Tallgrass Energy, LP's Current Report on Form 8-K files on March 11, 2019.)</u>
<u>3.7</u>	<u>Certificate of Formation of Tallgrass GP Holdings, LLC, dated March 28, 2013 (now known as Tallgrass Equity, LLC) (incorporated by reference to Exhibit 3.5 to Tallgrass Energy GP, LP's Registration Statement on Form S-1 filed February 24, 2015).</u>
<u>3.8</u>	<u>Certificate of Amendment to Certificate of Formation of Tallgrass GP Holdings, LLC, dated February 20, 2015 (now known as Tallgrass Equity, LLC) (incorporated by reference to Exhibit 3.6 to Tallgrass Energy GP, LP's Registration Statement on Form S-1 filed February 24, 2015).</u>
<u>3.9</u>	<u>Second Amended and Restated Limited Liability Company Agreement of Tallgrass Equity, LLC, dated May 12, 2015 (incorporated by reference to Exhibit 3.7 to Tallgrass Energy GP, LP's Quarterly Report on Form 10-Q filed on June 18, 2015).</u>
<u>4.1*</u>	<u>Description of Class A Shares</u>
<u>4.2</u>	<u>Specimen certificate representing Class A Shares (incorporated by reference to Exhibit 4.1 to Tallgrass Energy GP, LP's Registration Statement on Form S-1/A filed April 20, 2015).</u>
<u>4.3</u>	<u>Amended and Restated Registration Rights Agreement, dated March 11, 2019, by and among Tallgrass Energy, LP and each of the Holders listed on Annex A thereto (incorporated by reference to Exhibit 10.1 to Tallgrass Energy, LP's Current Report on Form 8-K filed on March 11, 2019).</u>
<u>4.4</u>	<u>Indenture, dated September 1, 2016, among Tallgrass Energy Partners, LP, Tallgrass Energy Finance Corp., the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Tallgrass Energy Partners, LP's Current Report on Form 8-K filed on September 1, 2016).</u>

- [4.5](#) [Form of 5.50% Senior Note due 2024 \(included as Exhibit A in Exhibit 4.1 which is incorporated by reference to Exhibit 4.1 to Tallgrass Energy Partners, LP's Current Report on Form 8-K filed on September 1, 2016\).](#)
- [4.6](#) [Supplemental Indenture, dated as of February 27, 2019, among Tallgrass Energy Partners, LP, Tallgrass Energy Finance Corp., the Guarantors party thereto and U.S. Bank National Association, as trustee, with respect to the Indenture governing the 5.50% Senior Notes due 2024 \(incorporated by reference to Exhibit 4.2 to Tallgrass Energy, LP's Current Report on Form 8-K filed on February 28, 2019\).](#)
- [4.7](#) [Indenture, dated September 15, 2017, among Tallgrass Energy Partners, LP, Tallgrass Energy Finance Corp., the Guarantors named therein and U.S. Bank National Association, as trustee. \(incorporated by reference to Exhibit 4.1 to Tallgrass Energy Partners, LP's Current Report on Form 8-K filed on September 15, 2017\).](#)
- [4.8](#) [Form of 5.50% Senior Note due 2028 \(included as Exhibit A in Exhibit 4.1 which is incorporated by reference to Exhibit 4.1 to Tallgrass Energy Partners, LP's Current Report on Form 8-K filed on September 15, 2017\).](#)
- [4.9](#) [Supplemental Indenture, dated as of February 27, 2019, among Tallgrass Energy Partners, LP, Tallgrass Energy Finance Corp., the Guarantors party thereto and U.S. Bank National Association, as trustee, with respect to the Indenture, governing the 5.50% Senior Notes due 2028 \(incorporated by reference to Exhibit 4.3 to Tallgrass Energy, LP's Current Report on Form 8-K filed on February 28, 2019\).](#)
- [4.10](#) [Indenture, dated as of September 26, 2018, among Tallgrass Energy Partners, LP, Tallgrass Energy Finance Corp., the Guarantors named therein and U.S. Bank National Association, as trustee \(incorporated by reference to Exhibit 4.1 to Tallgrass Energy, LP's Current Report on Form 8-K filed on September 26, 2018\).](#)
- [4.11](#) [Form of 4.75% Senior Note due 2023 \(included as Exhibit A in Exhibit 4.1 which is incorporated by reference to Exhibit 4.1 to Tallgrass Energy, LP's Current Report on Form 8-K filed on September 26, 2018\).](#)
- [4.12](#) [Supplemental Indenture, dated as of February 27, 2019, among Tallgrass Energy Partners, LP, Tallgrass Energy Finance Corp., the Guarantors party thereto and the U.S. Bank National Association, as trustee, with respect to the Indenture governing the 4.75% Senior Notes due 2023 \(incorporated by reference to Exhibit 4.1 to Tallgrass Energy, LP's Current Report on Form 8-K filed on February 28, 2019\).](#)
- [10.1](#) [Second Amended and Restated Limited Liability Company Agreement of Rockies Express Pipeline LLC, dated effective as of January 1, 2010, between TEP REX Holdings, LLC \(with respect to the 50% membership interest originally held by Kinder Morgan W2E Pipeline LLC and the 25% membership interest originally held by P&S Project I, LLC\) and Phillips 66 Company \(with respect to the 25% membership interest originally held by COPREX LLC\) \(incorporated by reference to Exhibit 10.4 to the Tallgrass Energy Partner's Quarterly Report on Form 10-Q filed on August 3, 2016\).](#)
- [10.2](#) [Amendment No. 1 to Second Amended and Restated Limited Liability Company Agreement of Rockies Express Pipeline LLC, dated effective as of November 13, 2012, between TEP REX Holdings, LLC \(with respect to the 50% membership interest originally held by Kinder Morgan W2E Pipeline LLC and the 25% membership interest originally held by P&S Project I, LLC\) and Phillips 66 Company \(with respect to the 25% membership interest originally held by COPREX LLC\) \(incorporated by reference to Exhibit 10.5 to Tallgrass Energy Partners, LP's Quarterly Report on Form 10-Q filed on August 3, 2016\).](#)
- [10.3](#) [Amendment No. 2 to Second Amended and Restated Limited Liability Company Agreement, dated effective as of May 5, 2016, between TEP REX Holdings, LLC \(with respect to the 50% membership interest originally held by Kinder Morgan W2E Pipeline LLC and the 25% membership interest originally held by P&S Project I, LLC\) and Phillips 66 Company \(with respect to the 25% membership interest originally held by COPREX LLC\) \(incorporated by reference to Exhibit 10.6 to Tallgrass Energy Partners, LP's Quarterly Report on Form 10-Q filed on August 3, 2016\).](#)
- [10.4](#) [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 \(incorporated by reference to Exhibit 10.1 to Tallgrass Energy Partners, LP's Quarterly Report on Form 10-Q filed on August 2, 2017\).](#)
- [10.5](#) [Amendment No. 1 to Second Amended and Restated Credit Agreement, dated July 26, 2018, by and among Tallgrass Energy Partners, LP, the subsidiary guarantors named therein, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto \(incorporated by reference to Exhibit 10.1 to Tallgrass Energy, LP's Current Report on Form 8-K filed on July 27, 2018\).](#)
- [10.6](#) [Consent and Amendment No. 2 to Second Amended and Restated Credit Agreement, dated as of February 22, 2019, by and among Tallgrass Energy Partners, LP, the subsidiary guarantors named therein, Wells Fargo Bank, National Association, as administrative agent, and the required lenders named therein \(incorporated by reference to Exhibit 10.1 to Tallgrass Energy, LP's Current Report on Form 8-K filed on February 28, 2019\).](#)

<u>10.7</u>	<u>Support Agreement, dated December 16, 2019, by and among Tallgrass Energy, LP, Prairie Non-ECI Acquiror LP, Prairie ECI Acquiror LP, Prairie VCOC Acquiror LP, Prairie Secondary Acquiror LP and Prairie Secondary Acquiror E LP (incorporated by reference to Exhibit 10.1 to Tallgrass Energy, LP's Current Report on Form 8-K filed on December 17, 2019).</u>
<u>10.8†</u>	<u>Tallgrass Energy GP, LLC Long-Term Incentive Plan (as amended and restated effective August 2, 2018) (incorporated by reference to Exhibit 10.1 to Tallgrass Energy, LP's Quarterly Report on Form 10-Q filed on August 2, 2018).</u>
<u>10.9†</u>	<u>Tallgrass MLP GP, LLC Long-Term Incentive Plan (as amended and restated effective August 2, 2018) (incorporated by reference to Exhibit 10.2 to Tallgrass Energy, LP's Quarterly Report on Form 10-Q filed on August 2, 2018).</u>
<u>10.10†</u>	<u>Form of Employee Equity Participation Share Agreement (incorporated by reference to Exhibit 4.5 to the Partnership's Registration Statement on Form S-8 filed on July 17, 2015).</u>
<u>10.11†</u>	<u>Form of Employee Equity Participation Unit Agreement (incorporated by reference to Exhibit 4.5 to Tallgrass Energy Partners, LP's Registration Statement on Form S-8 filed on June 18, 2013).</u>
<u>10.12†</u>	<u>Form of Employee Equity Participation Unit Agreement (incorporated by reference to Exhibit 10.1 to Tallgrass Energy Partners, LP's Current Report on Form 10-Q filed on November 2, 2017).</u>
<u>10.13†</u>	<u>Form of Equity Participation Share Agreement (incorporated by reference to Exhibit 10.3 to Tallgrass Energy, LP's Quarterly Report on Form 10-Q filed on August 2, 2018).</u>
<u>10.14†</u>	<u>Form of Indemnification Agreement (incorporated by reference to Exhibit 10.2 to Tallgrass Energy, LP's Current Report on Form 8-K filed on March 11, 2019).</u>
<u>10.15†</u>	<u>Third Amended and Restated Employment Agreement, dated March 11, 2019, by and among Tallgrass Management, LLC, Tallgrass Energy GP, LLC and David G. Dehaemers, Jr. (incorporated by reference to Exhibit 10.3 to Tallgrass Energy, LP's Current Report on Form 8-K filed on March 11, 2019).</u>
<u>10.16†</u>	<u>Employment Agreement, dated November 24, 2019, by and among Tallgrass Energy GP, LLC, Tallgrass Management, LLC and William R. Moler (incorporated by reference to Exhibit 10.1 to Tallgrass Energy, LP's Current Report on Form 8-K filed on November 25, 2019).</u>
<u>10.17†</u>	<u>Employment Agreement, dated December 3, 2019, by and among Tallgrass Management, LLC, Tallgrass Energy GP, LLC, and Matthew Sheehy (incorporated by reference to Exhibit 10.1 to Tallgrass Energy, LP's Current Report on Form 8-K filed on December 3, 2019).</u>
<u>10.18†</u>	<u>Form of Employment Agreement entered into by Tallgrass Energy GP, LLC, Tallgrass Management, LLC and each of Gary J. Brauchle, Christopher R. Jones and Gary D. Watkins (incorporated by reference to Exhibit 10.4 to Tallgrass Energy, LP's Current Report on Form 8-K filed on March 11, 2019).</u>
<u>21.1*</u>	<u>List of Subsidiaries of Tallgrass Energy, LP.</u>
<u>23.1*</u>	<u>Consent of Deloitte & Touche LLP on Consolidated Financial Statements of Tallgrass Energy, LP and the effectiveness of Tallgrass Energy, LP's internal control over financial reporting.</u>
<u>23.2*</u>	<u>Consent of Deloitte & Touche LLP on Financial Statements of Rockies Express Pipeline LLC.</u>
<u>23.3*</u>	<u>Consent of PricewaterhouseCoopers LLP on Consolidated Financial Statements of Tallgrass Energy, LP.</u>
<u>23.4*</u>	<u>Consent of PricewaterhouseCoopers LLP on Financial Statements of Rockies Express Pipeline LLC.</u>
<u>31.1*</u>	<u>Rule 13a-14(a)/15d-14(a) Certification of William R. Moler.</u>
<u>31.2*</u>	<u>Rule 13a-14(a)/15d-14(a) Certification of Gary J. Brauchle.</u>
<u>32.1*</u>	<u>Section 1350 Certification of William R. Moler.</u>
<u>32.2*</u>	<u>Section 1350 Certification of Gary J. Brauchle.</u>
101.INS*	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL 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.

104* Cover Page Interactive Data File - the cover page interactive data file does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document (included as Exhibit 101).

* - filed herewith

† - Management contract of compensatory plan or arrangement required to be filed as an exhibit to this Form 10-K pursuant to Item 15(b).

Item 16. Form 10-K Summary

Not applicable.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Tallgrass Energy, LP

By: Tallgrass Energy GP, LLC, its general partner

By: /s/ William R. Moler

William R. Moler

Chief Executive Officer of Tallgrass Energy GP, LLC
(the general partner of Tallgrass Energy, LP)

Date: February 12, 2020

SIGNATURES

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

<i>Name</i>	<i>Title</i>	<i>Date</i>
<u>/s/ William R. Moler</u> William R. Moler	Director and Chief Executive Officer (Principal Executive Officer)	February 12, 2020
<u>/s/ Gary J. Brauchle</u> Gary J. Brauchle	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 12, 2020
<u>/s/ Gary D. Watkins</u> Gary D. Watkins	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 12, 2020
<u>/s/ Marcelino Oreja Arburua</u> Marcelino Oreja Arburua	Director	February 12, 2020
<u>/s/ Guy G. Buckley</u> Guy G. Buckley	Director	February 12, 2020
<u>/s/ Roy N. Cook</u> Roy N. Cook	Director	February 12, 2020
<u>/s/ Thomas A. Gerke</u> Thomas A. Gerke	Director	February 12, 2020
<u>/s/ Wallace C. Henderson</u> Wallace C. Henderson	Director	February 12, 2020
<u>/s/ Matthew J.K. Runkle</u> Matthew J.K. Runkle	Director	February 12, 2020
<u>/s/ Terrance D. Towner</u> Terrance D. Towner	Director	February 12, 2020

Description of Class A Shares

The following description of the Class A shares representing limited partner interests ("Class A shares") in Tallgrass Energy, LP ("TGE" or, as the context requires, "we," "us" or "our") is a summary and is subject to, and qualified in its entirety by, reference to the provisions of our Second Amended and Restated Agreement of Limited Partnership, dated as of July 1, 2018 (referred to herein as our "partnership agreement"), which has been filed as Exhibit 3.3 to our Annual Report on Form 10-K for the year ended December 31, 2019, of which this Exhibit 4.1 is a part (referred to herein as our "Annual Report").

Our Class A shares represent limited partner interests in us and are listed on the New York Stock Exchange under the symbol "TGE."

Dividend Rights

Our Cash Distribution Policy

Our partnership agreement requires that, within 55 days after the end of each quarter, we distribute our available cash to Class A shareholders of record on the applicable record date.

Available cash is defined in our partnership agreement and generally means, with respect to any calendar quarter, all cash and cash equivalents on hand at the date of determination of available cash for the distribution in respect of such calendar quarter (including distributions received from Tallgrass Equity, LLC ("Tallgrass Equity") in respect of such quarter), less the amount of cash reserves established by our general partner, which will not be subject to a cap, to:

- comply with applicable law;
- comply with any agreement binding upon us or our subsidiaries (exclusive of Tallgrass Energy Partners, LP and its subsidiaries);
- provide for future capital expenditures, debt service and other credit needs as well as any federal, state, provincial or other income tax that may affect us in the future; or
- otherwise provide for the proper conduct of our business.

Our available cash also includes cash on hand resulting from borrowings made after the end of the quarter.

As further discussed in Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations, "Dividends," of our Annual Report, pursuant to the Take-Private Merger Agreement, we have agreed not to pay dividends during the pendency of the transactions contemplated by the Take-Private Merger Agreement.

Distributions of Cash upon Liquidation

If we dissolve in accordance with our partnership agreement, we will sell or otherwise dispose of our assets in a process called a liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to the holders of our Class A shares in accordance with their respective pro-rata interests in Class A shares.

Limited Voting Rights

Our general partner manages us and our operations. Our Class A shareholders have only limited voting rights on matters affecting our business. Our Class A shareholders do not have the right to elect our general partner or its directors on an annual or other continuing basis.

The following is a summary of the shareholder vote required for the matters specified below. On all matters where our shareholders are entitled to vote, the Class A shares will vote together with our Class B shares representing limited partner interests ("Class B shares") as a single class and will be entitled to one vote per share. The holders of a majority of the outstanding Class A shares and Class B shares, represented in person or by proxy, will constitute a quorum unless any action by the shareholders requires approval by holders of a greater percentage of the shares, in which case the quorum will be the greater percentage. In voting their shares, our general partner and its affiliates will have no fiduciary duty or obligation whatsoever to us or the shareholders, including any duty to act in good faith or in the best interests of us or the shareholders.

Issuance of additional shares (or other partnership securities)	No voting or approval right. Please read "—Issuance of Additional Securities."
Amendment of our Partnership Agreement	Amendments to our partnership agreement may be proposed only by or with the consent of our general partner. Certain amendments may be made by our general partner without the approval of our shareholders. Other amendments generally require the approval of a majority of our outstanding shares. Please read "—Amendments to Our Partnership Agreement."
Merger of our partnership or the sale of all or substantially all of our assets	A majority of our outstanding shares in certain circumstances. Please read "—Merger, Sale or Other Disposition of Assets."
Dissolution	A majority of our outstanding shares. Please read "—Termination or Dissolution."
Reconstitution upon dissolution.	A majority of our outstanding shares. Please read "—Termination or Dissolution."
Withdrawal of our general partner	No voting or approval right. Please read "—Withdrawal or Removal of the General Partner."
Removal of our general partner	Not less than 80% of our outstanding shares. Please read "—Withdrawal or Removal of the General Partner."
Transfer of the general partner interest	No voting or approval right. Please read "—Transfer of General Partner Interest."

Unless otherwise indicated, "outstanding shares" includes Class B shares and shares held by our general partner and its affiliates.

Issuance of Additional Securities

Our partnership agreement authorizes us to issue an unlimited number of additional limited partner interests and other equity securities for the consideration and on the terms and conditions established by our general partner in its sole discretion without the approval of our shareholders.

It is possible that we will fund acquisitions through the issuance of additional shares or other equity securities. Holders of any additional shares we issue may be entitled to share equally with the then-existing shareholders in our cash distributions made following the date such holders become holders of record of the additional shares. In addition, the issuance of additional partnership interests may dilute the value of the interests of the then-existing holders of shares in our net assets.

In accordance with the Delaware Revised Uniform Limited Partnership Act (the "Delaware Act") and the provisions of our partnership agreement, we may also issue additional partnership interests that have special voting rights to which the Class A shares are not entitled.

Amendments to Our Partnership Agreement

General

Amendments to our partnership agreement may be proposed only by or with the consent of our general partner. However, our general partner will have no duty or obligation to propose any amendment to our partnership agreement and may decline to do so free of any duty or obligation whatsoever to us or our shareholders, including any duty to act in good faith or in the best interests of us or our shareholders. To adopt a proposed amendment, other than the amendments discussed below, our general partner must seek written approval of the holders of the number of shares required to approve the amendment or call a meeting of our shareholders to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by a majority of our outstanding shares.

Prohibited Amendments

No amendment may be made that would:

- (1) enlarge the obligations of any shareholder without its consent, unless approved by at least a majority of the type or class of shareholder interests so affected; or
- (2) enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without the consent of our general partner, which may be given or withheld in its sole discretion.

- (3) The provision of our partnership agreement preventing the amendments having the effects described in clauses (1) or (2) above can be amended upon the approval of the holders of at least 90% of the outstanding shares.

No Shareholder Approval

Our general partner may generally make amendments to our partnership agreement without the approval of any shareholder or assignee to reflect:

- (1) any change in our name, the location of our principal place of business, our registered agent or its registered office;
- (2) the admission, substitution, withdrawal or removal of partners in accordance with our partnership agreement;
- (3) a change that our general partner determines to be necessary or appropriate to qualify or continue the qualification of our partnership as a limited partnership or a partnership in which the limited partners have limited liability under the laws of any state;
- (4) an amendment that is necessary, in the opinion of our counsel, to prevent us or our general partner or its directors, officers, agents or trustees, from in any manner being subjected to the provisions of the Investment Company Act of 1940, the Investment Advisors Act of 1940, or "plan asset" regulations adopted under the Employee Retirement Income Security Act of 1974, whether or not substantially similar to plan asset regulations currently applied or proposed;
- (5) an amendment that our general partner determines to be necessary or appropriate for the authorization of additional partnership securities or rights to acquire partnership securities;
- (6) any amendment expressly permitted in our partnership agreement to be made by our general partner acting alone;
- (7) an amendment effected, necessitated or contemplated by a merger agreement that has been approved under the terms of our partnership agreement;
- (8) an amendment that our general partner determines to be necessary or appropriate for the formation by us, or our investment in, any corporation, partnership or other entity, as otherwise permitted by our partnership agreement;
- (9) a change in our fiscal year or taxable year and related changes;
- (10) a merger with or conveyance to another limited liability entity that is newly formed and has no assets, liabilities or operations at the time of the merger or conveyance other than those it receives by way of the merger or conveyance, provided that the sole purpose of such merger is to effect a legal change into a different form of limited liability entity; or
- (11) any other amendments substantially similar to any of the matters described in (1) through (10) above.

In addition, our general partner may make amendments to our partnership agreement without the approval of any shareholder or assignee if those amendments, in the discretion of our general partner:

- do not adversely affect our shareholders (or any particular class of holders of partnership interests) in any material respect;
- are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;
- are necessary or appropriate to facilitate the trading of our shares or to comply with any rule, regulation, guideline or requirement of any securities exchange on which our shares are or will be listed for trading;
- are necessary or appropriate for any action taken by our general partner relating to splits or combinations of shares under the provisions of our partnership agreement; or
- are required to effect the intent of the statements contained in this prospectus and in the provisions of our partnership agreement or as are otherwise contemplated by our partnership agreement.

Opinion of Counsel and Shareholder Approval

Any amendment described as requiring shareholder approval will require an opinion of counsel to the effect that the amendment will not affect the limited liability under applicable law of any of our shareholders. Our general partner will not be required to obtain such an opinion of counsel for any of the amendments described above under "*—Amendments to Our Partnership Agreement—No Shareholder Approval.*" In the absence of such an opinion where required, the approval of 90% of the outstanding shares is required for an amendment to become effective.

In addition to the above restrictions, any amendment that would have a material adverse effect on the rights or preferences of any type or class of outstanding shares in relation to other classes of shares will require the approval of at least a majority of the type or class of shares so affected. Also, any amendment that reduces the voting percentage required to take any action must be approved by the affirmative vote of shareholders whose aggregate outstanding shares constitute not less than the voting requirement sought to be reduced.

Merger, Sale or Other Disposition of Assets

Our partnership agreement generally prohibits our general partner, without the prior approval of a majority of our outstanding shares, from causing us to, among other things, sell, exchange or otherwise dispose of all or substantially all of our assets in a single transaction or a series of related transactions. Our general partner may, however, mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without that approval. Our general partner may also sell all or substantially all of our assets under a foreclosure or other realization upon those encumbrances without that approval.

A merger, consolidation or conversion of us requires the prior consent of our general partner. In addition, our partnership agreement provides that, to the maximum extent permitted by law, our general partner will have no duty or obligation to consent to any merger, consolidation or conversion of us and may decline to do so free of any duty or obligation whatsoever to us, or any of our shareholders. Further, in declining to consent to a merger, consolidation or conversion, our general partner will not be required to act in good faith or pursuant to any other standard imposed by our partnership agreement, any other agreement, under the Delaware Act or any other law, rule or regulation or at equity.

If conditions specified in our partnership agreement are satisfied, our general partner may merge us or any of our subsidiaries into, or convey some or all of our assets to, a newly formed entity if the sole purpose of that merger or conveyance is to effect a mere change in our legal form into another limited liability entity. Our shareholders are not entitled to dissenters' rights or appraisal rights (and, therefore, will not be entitled to demand payment of a fair price for their shares) under our partnership agreement or applicable Delaware law in the event of a merger or consolidation, a sale of substantially all of our assets or any other transaction or event.

Termination or Dissolution

We will continue as a limited partnership until terminated under our partnership agreement. We will dissolve upon:

- (1) the election of our general partner to dissolve us, if approved by a majority of our outstanding shares;
- (2) there being no holders of partnership interests, unless we are continued without dissolution in accordance with applicable Delaware law;
- (3) the entry of a decree of judicial dissolution of us; or
- (4) the withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner other than by reason of a transfer of its general partner interest in accordance with our partnership agreement or withdrawal or removal of our general partner following approval and admission of a successor.

Upon the withdrawal or removal of our general partner, notice thereof, or a dissolution under clause (4) above, the holders of a majority of our outstanding shares may elect, within 90 or 180 days, depending on the circumstances leading to such withdrawal, removal or dissolution, to continue our business on the same terms and conditions described in our partnership agreement by appointing as a successor general partner an entity approved by the holders of a majority of the outstanding shares, subject to our receipt of an opinion of counsel to the effect that the action would not result in the loss of limited liability of any limited partner.

Liquidation and Distribution of Proceeds

Upon our dissolution, unless we are reconstituted and continued as a new limited partnership, the person authorized to wind up our affairs (the liquidator) will, acting with all of the powers of our general partner that the liquidator deems necessary or appropriate, liquidate our assets. The proceeds of the liquidation will be applied as follows:

- first, towards the payment of all of our creditors and the settlement of or creation of a reserve for contingent liabilities; and
- then, to all holders of Class A shares in accordance with their pro-rata interest in Class A shares.

If the liquidator determines that a sale would be impractical or would cause a loss to our partners, it may defer liquidation of our assets for a reasonable period of time or distribute assets, in whole or in part, in kind.

Withdrawal or Removal of the General Partner

Our general partner may withdraw as general partner in compliance with our partnership agreement after giving 90 days' advance notice to our shareholders, and that withdrawal will not constitute a breach of our partnership agreement.

Upon notice of the voluntary withdrawal of our general partner, the holders of a majority of our outstanding shares may elect a successor to that withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability cannot be obtained, we will be dissolved, wound up and liquidated; *provided, however*, that within 90 days after that withdrawal, the holders of a majority of the outstanding shares may elect to continue our business on the same terms and conditions described in our partnership agreement by appointing as a successor general partner an entity approved by the holders of a majority of the outstanding shares, subject to our receipt of an opinion of counsel to the effect that the action would not result in the loss of limited liability of any limited partner. Please read "*Termination or Dissolution*" above.

Our general partner may not be removed unless that removal is approved by the vote of the holders of not less than 80% of our outstanding shares, including shares held by our general partner and its affiliates, and we receive an opinion of counsel regarding limited liability. Any removal of our general partner is also subject to the approval of a successor general partner by the vote of the holders of a majority of the outstanding shares. The ownership of more than 20% of our outstanding shares by any person or group would give such persons the practical ability to prevent our general partner's removal. As of December 31, 2019, affiliates of Blackstone Infrastructure Partners owned approximately 44.1% of the combined voting power of our Class A and Class B shares, which enables such entities to prevent our general partner's removal.

Transfer of General Partner Interest

Our general partner may transfer all or any of its general partner interest in us without obtaining approval of any shareholder. As a condition of this transfer, the transferee must assume the rights and duties of the general partner to whose interest that transferee has succeeded, agree to be bound by the provisions of our partnership agreement and furnish an opinion of counsel regarding limited liability.

Transfer of Class A Shares

By transfer of our Class A shares in accordance with our partnership agreement, each transferee of our Class A shares will be admitted as a shareholder with respect to the class of shares transferred when such transfer and admission is reflected in our books and records. Additionally, each transferee of our Class A:

- represents that the transferee has the capacity, power and authority to become bound by our partnership agreement;
- automatically agrees to be bound by the terms and conditions of, and is deemed to have executed, our partnership agreement; and
- gives the consents and approvals contained in our partnership agreement, such as the approval of all transactions and agreements that we are entering into in connection with our formation and this offering.

A transferee will become a substituted limited partner for the transferred Class A shares automatically upon the recording of the transfer on our books and records. Our general partner will cause any transfers to be recorded on our books and records no less frequently than quarterly.

We may, at our discretion, treat the nominee holder of a Class A share, as applicable, as the absolute owner. In that case, the beneficial holder's rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Class A shares are securities and are transferable according to the laws governing transfers of securities. In addition to other rights acquired upon transfer, the transferor gives the transferee the right to become a substituted limited partner in TGE for the transferred shares.

Until a Class A share has been transferred on our books, we and the transfer agent, notwithstanding any notice to the contrary, may treat the record holder of the Class A share as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

Transfer Agent and Registrar

Duties

American Stock Transfer and Trust Company serves as registrar and transfer agent for our Class A shares. We will pay all fees charged by the transfer agent for transfers of our Class A shares except the following that must be paid by shareholders:

- surety bond premiums to replace lost or stolen certificates, taxes and other governmental charges;
- special charges for services requested by a holder of a Class A share; and

- other similar fees or charges.

There will be no charge to holders of Class A shares for disbursements of our cash distributions. Tallgrass Equity, LLC will indemnify the transfer agent and its directors, officers, employees, affiliates and agents against any actions, claims, losses, liability or reasonable expenses (including legal and other fees and expenses) incurred by or asserted against the indemnified person or entity arising out of or in connection with entering into the agreement with the transfer agent, the performance of the transfer agent's duties thereunder or the enforcement of the indemnity under the agreement with the transfer agent, except for such losses, liabilities or expenses incurred as a result of the indemnified person's or entity's gross negligence, bad faith or willful misconduct.

Resignation or Removal

The transfer agent may at any time resign, by notice to us, or be removed by us. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If no successor has been appointed and accepted the appointment within 30 days after notice of the resignation or removal, we are authorized to act as the transfer agent and registrar until a successor is appointed.

Change of Management Provision

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove our general partner as general partner or otherwise change management. If any person or group other than our general partner, its permitted transferees or its affiliates acquires beneficial ownership of 20% or more of any class of our shares, that person or group loses voting rights on all of its shares. This loss of voting rights does not apply to (i) any person or group that acquires the shares directly from us, our general partner or any of our general partner's affiliates, (ii) any transferees that acquired the shares from a person or group described in clause (i), or (iii) any person or group that acquires 20% of any class of shares with the prior approval of the board of directors of our general partner.

Limited Call Right

If at any time more than 80% of our outstanding shares (including Class A shares issuable upon the exchange of Class B shares and including any other additional limited partner interests we may issue in the future) are owned by our general partner or its affiliates, our general partner will have the right (which it may assign in whole or in part to us or any of its affiliates), but not the obligation, to acquire all, but not less than all, of the remaining shares of such class held by unaffiliated persons as of a record date to be selected by our general partner, on at least 10 but not more than 60 days' notice. The purchase price in the event of this purchase is the greater of:

- the highest price paid by our general partner and its affiliates for any shares of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those shares; and
- the current market price calculated in accordance with our partnership agreement as of the date three business days before the date the notice is mailed.

As a result of our general partner's right to purchase outstanding limited partner interests, a holder of limited partner interests may have his limited partner interests purchased at an undesirable time or price. The tax consequences to a shareholder of the exercise of this call right are the same as a sale by that shareholder of his shares in the market. Please read "Material U.S. Federal Income Tax Consequences."

Limited Liability

Assuming that a shareholder does not participate in the operation, management or control of our business within the meaning of the Delaware Act and that he, she or it otherwise acts in conformity with the provisions of our partnership agreement, liability under the Delaware Act will be limited, subject to possible exceptions, to the amount of capital he, she or it is obligated to contribute to us for his, her or its shares plus his or its pro rata share of any undistributed profits and assets. If it were determined, however, that the right, or exercise of the right, by the shareholders as a group:

- to remove or replace our general partner;
- to approve some amendments to our partnership agreement; or
- to take other action under our partnership agreement,

constituted "participation in the control" of our business for the purposes of the Delaware Act, then our shareholders could be held personally liable for our obligations under the laws of Delaware, to the same extent as our general partner. This liability would extend to persons who transact business with us who reasonably believe that the shareholder is a general partner. Neither our partnership agreement nor the Delaware Act specifically provides for legal recourse against our general partner if a shareholder were to lose limited liability through any fault of our general partner. Although this does not mean that a shareholder could not seek legal recourse, we know of no precedent for this type of a claim in Delaware case law.

Under the Delaware Act, a limited partnership may not make a distribution to a partner if, after the distribution, all liabilities of the limited partnership, other than liabilities to partners on account of their partnership interests and liabilities for which the recourse of creditors is limited to specific property of the partnership, would exceed the fair value of the assets of the limited partnership. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited will be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act will be liable to the limited partnership for the amount of the distribution for three years. Under the Delaware Act, a substituted limited partner of a limited partnership is liable for the obligations of his assignor to make contributions to the partnership, except that such person is not obligated for liabilities unknown to him at the time he became a limited partner and that could not be ascertained from the partnership agreement.

Limitations on the liability of limited partners for the obligations of a limited partner (or in our case, a shareholder) have not been clearly established in many jurisdictions. Although we currently have no operations distinct from our controlling membership interest in Tallgrass Equity, if in the future, by our ownership in an operating company or otherwise, it were determined that we were conducting business in any state without compliance with the applicable limited partnership or limited liability company statute, or that the right or exercise of the right by the shareholders as a group to remove or replace our general partner, to approve some amendments to our partnership agreement, or to take other action under our partnership agreement constituted "participation in the control" of our business for purposes of the statutes of any relevant jurisdiction, then the shareholder could be held personally liable for our obligations under the law of that jurisdiction to the same extent as our general partner under the circumstances. We will operate in a manner that our general partner considers reasonable and necessary or appropriate to preserve the limited liability of the shareholders.

**Tallgrass Energy, LP
Subsidiaries**

Company	Jurisdiction of Organization
Alpha Reclaim Technology, LLC.....	Texas
BNN Colorado Water, Inc.	Colorado
BNN Colorado Water, LLC.....	Delaware
BNN Eastern, LLC.....	Delaware
BNN Great Plains, LLC	Delaware
BNN North Dakota, LLC.....	Delaware
BNN Recycle, LLC.....	Delaware
BNN Redtail, LLC	Delaware
BNN South Texas, LLC	Delaware
BNN Water Solutions, LLC	Delaware
BNN West Texas, LLC.....	Delaware
BNN Western, LLC.....	Delaware
CES Holding Company, Inc.....	Delaware
Deeprock Development, LLC	Delaware
K & H Partners LLC	West Virginia
Plaquemines Liquids Terminal, LLC	Delaware
Seahorse Pipeline, LLC.....	Delaware
Stanchion Energy, LLC.....	Delaware
Tallgrass Cheyenne Connector Holdings, LLC	Delaware
Tallgrass Cheyenne Connector Operator, LLC.....	Delaware
Tallgrass Colorado Pipeline, Inc.	Colorado
Tallgrass Energy Finance Corp.	Delaware
Tallgrass Energy Investments, LLC.....	Delaware
Tallgrass Energy Partners, LP	Delaware
Tallgrass Equity Investments, LLC.....	Delaware
Tallgrass Equity, LLC	Delaware
Tallgrass Interstate Gas Transmission, LLC	Colorado
Tallgrass Management, LLC.....	Delaware
Tallgrass Midstream Gathering, LLC	Colorado
Tallgrass Midstream, LLC	Delaware
Tallgrass MLP GP, LLC.....	Delaware
Tallgrass MLP Operations, LLC	Delaware
Tallgrass NatGas Operator, LLC.....	Delaware
Tallgrass PLT Operator, LLC	Delaware
Tallgrass Pony Express Pipeline, LLC.....	Delaware
Tallgrass PRG Holdings, LLC	Delaware
Tallgrass PRG Operator, LLC.....	Delaware
Tallgrass Sterling Terminal, LLC.....	Delaware
Tallgrass Terminals, LLC.....	Delaware
TEP REX Holdings, LLC.....	Delaware
Trailblazer Pipeline Company LLC.....	Delaware

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-225382 on Form S-3, Registration Statement No. 333-226086 on Form S-3/ASR, and Registration Statement Nos. 333-226537 and 333-205717 on Form S-8 of our reports dated February 12, 2020, relating to the financial statements of Tallgrass Energy, LP (the "Partnership") and the effectiveness of the Partnership's internal control over financial reporting, appearing in this Annual Report on Form 10-K for the year ended December 31, 2019.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 12, 2020

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-225382 on Form S-3, Registration Statement No. 333-226086 on Form S-3/ASR, and Registration Statement Nos. 333-226537 and 333-205717 on Form S-8 of Tallgrass Energy, LP, of our report dated February 12, 2020, relating to the financial statements of Rockies Express Pipeline LLC, appearing in this Annual Report on Form 10-K of Tallgrass Energy, LP for the year ended December 31, 2019.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 12, 2020

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Forms S-3 (No. 333-225382), S-3/ASR (No. 333-226086) and S-8 (No. 333-226537 and 333-205717) of Tallgrass Energy, LP of our report dated February 8, 2019 relating to the financial statements, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Denver, Colorado
February 12, 2020

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Forms S-3 (No. 333-225382), S-3/ASR (No. 333-226086) and S-8 (No. 333-226537 and 333-205717) of Tallgrass Energy, LP of our report dated February 8, 2019 relating to the financial statements Rockies Express Pipeline LLC, which appears in this Form 10-K of Tallgrass Energy, LP.

/s/ PricewaterhouseCoopers LLP

Denver, Colorado
February 12, 2020

**Certification by Chief Executive Officer pursuant to
Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934,
as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**

I, William R. Moler, certify that:

1. I have reviewed this Annual Report on Form 10-K of Tallgrass Energy, LP;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

By: /s/ William R. Moler

William R. Moler

Chief Executive Officer of Tallgrass Energy GP, LLC
(the general partner of Tallgrass Energy, LP)

Date: February 12, 2020

**Certification by Chief Financial Officer pursuant to
Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934,
as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**

I, Gary J. Brauchle, certify that:

1. I have reviewed this Annual Report on Form 10-K of Tallgrass Energy, LP;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

By: /s/ Gary J. Brauchle

Gary J. Brauchle

Executive Vice President and Chief Financial Officer of
Tallgrass Energy GP, LLC (the general partner of
Tallgrass Energy, LP)

Date: February 12, 2020

**Certification Pursuant to
18 U.S.C. Section 1350,
as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002**

In connection with the annual report of Tallgrass Energy, LP (the “Partnership”) on Form 10-K for the year ended December 31, 2019, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, William R. Moler, Chief Executive Officer of Tallgrass Energy GP, LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (“Section 906”), that, to my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

By: /s/ William R. Moler

William R. Moler

Chief Executive Officer of Tallgrass Energy GP, LLC (the
general partner of Tallgrass Energy, LP)

Date: February 12, 2020

A signed original of this written statement required by Section 906 has been provided to the Partnership and will be retained and furnished to the Securities and Exchange Commission or its staff upon request.

**Certification Pursuant to
18 U.S.C. Section 1350,
as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002**

In connection with the annual report of Tallgrass Energy, LP (the “Partnership”) on Form 10-K for the year ended December 31, 2019, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Gary J. Brauchle, Executive Vice President and Chief Financial Officer of Tallgrass Energy GP, LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (“Section 906”), that, to my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

By: /s/ Gary J. Brauchle

Gary J. Brauchle

Executive Vice President and Chief Financial Officer of
Tallgrass Energy GP, LLC (the general partner of
Tallgrass Energy, LP)

Date: February 12, 2020

A signed original of this written statement required by Section 906 has been provided to the Partnership and will be retained and furnished to the Securities and Exchange Commission or its staff upon request.

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CORPORATE INFORMATION

BOARD OF DIRECTORS

William R. Moler
Marcelino Oreja Arburua
Guy G. Buckley
Roy N. Cook
Thomas A. Gerke
Wallace C. Henderson
Matthew J.K. Runkle
Terrance D. Towner

EXECUTIVE MANAGEMENT

William R. Moler
Chief Executive Officer
Matthew P. Sheehy
President
Gary J. Brauchle*
Executive Vice President &
Chief Financial Officer
Christopher R. Jones
Executive Vice President,
General Counsel & Secretary
Gary D. Watkins*
Senior Vice President &
Chief Accounting Officer

**Mr. Brauchle resigned effective
February 14, 2020 and Mr. Watkins
was appointed as EVP and CFO
effective such date.*

PUBLIC HEADQUARTERS

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Suite 350
Leawood, KS 66211
(913) 928-6060

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370 Van Gordon Street
Lakewood, CO 80228
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INVESTOR RELATIONS

(913) 928-6012
investor.relations@tallgrassenergy.com

MEDIA RELATIONS

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media.relations@tallgrassenergy.com

TRANSFER AGENT

American Stock Transfer and Trust

TICKER SYMBOL

NYSE: TGE





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