DCP Midstream, LP
Form 10-K
February 15, 2017
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)
ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2016
or
¨TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number: 001-32678

DCP MIDSTREAM, LP
(Exact name of registrant as specified in its charter)

Delaware	03-0567133
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
370 17th Street, Suite 2500 Denver, Colorado	80202
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (303) 595-3331
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class:	Name of Each Exchange on Which Registered:
Common Units Representing Limited Partner Interests	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 Exchange Act of 1934, or the Act. YesýNo¨
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 ý
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Act 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. YesýNo¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit

and post such files). Yes ý No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

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

The aggregate market value of common units held by non-affiliates of the registrant on June 30, 2016, was approximately $3,121,014,000. The aggregate market value was computed by reference to the last sale price of the registrant's common units on the New York Stock Exchange on June 30, 2016.

As of February 3, 2017, there were 143,302,328 common units representing limited partner interests outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

DCP MIDSTREAM, LP
FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2016
TABLE OF CONTENTS

GLOSSARY OF TERMS

The following is a list of certain industry terms used throughout this report:

Bbl	barrel
Bbls/d	barrels per day
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
Btu	British thermal unit, a measurement of energy
Fractionation	the process by which natural gas liquids are separated into individual components
MBbls	thousand barrels
MBbls/d	thousand barrels per day
MMBtu	million Btus
MMBtu/d	million Btus per day
MMcf	million cubic feet
MMcf/d	million cubic feet per day
NGLs	natural gas liquids
Throughput	the volume of product transported or passing through a pipeline or other facility

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Our reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. You can typically identify forward-looking statements by the use of forward-looking words, such as “may,” “could,” “should,” “intend,” “assume,” “project,” “believe,” “anticipate,” “expect,” “es “potential,” “plan,” “forecast” and other similar words.

All statements that are not statements of historical facts, including, but not limited to, statements regarding our future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements.

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the risks set forth in Item 1A. "Risk Factors” in this Annual Report on Form 10-K, including the following risks and uncertainties:

- the extent of changes in commodity prices and the demand for our products and services, our ability to effectively limit a portion of the adverse impact of potential changes in commodity prices through derivative financial instruments, and the potential impact of price, and of producers’ access to capital on natural gas drilling, demand for our services, and the volume of NGLs and condensate extracted;
- the demand for crude oil, residue gas and NGL products;
- the level and success of drilling and quality of production volumes around our assets and our ability to connect supplies to our gathering and processing systems, as well as our residue gas and NGL infrastructure;
- volatility in the price of our common units;
- our ability to hire, train, and retain qualified personnel and key management to execute our business strategy;
- general economic, market and business conditions;
- our ability to continue the safe and reliable operation of our assets;
- our ability to grow through organic growth projects, or acquisitions, and the successful integration and future performance of such assets;
- our ability to access the debt and equity markets and the resulting cost of capital, which will depend on general market conditions, our financial and operating results, inflation rates, interest rates, our ability to comply with the covenants in our credit agreement and the indentures governing our notes, as well as our ability to maintain our credit ratings;
- new, additions to, and changes in, laws and regulations, particularly with regard to taxes, safety and protection of the environment, including, but not limited to, climate change legislation, regulation of over-the-counter derivatives market and entities, and hydraulic fracturing regulations, or the increased regulation of our industry, and their impact on producers and customers served by our systems;
- the creditworthiness of our customers and the counterparties to our transactions;
- the amount of collateral we may be required to post from time to time in our transactions;
- industry changes, including the impact of bankruptcies, consolidations, alternative energy sources, technological advances and changes in competition;
- our ability to construct and start up facilities on budget and in a timely fashion, which is partially dependent on obtaining required construction, environmental and other permits issued by federal, state and municipal governments, or agencies thereof, the availability of specialized contractors and laborers, and the price of and demand for materials;
- weather, weather-related conditions and other natural phenomena, including, but not limited to, their potential impact on demand for the commodities we sell and the operation of company-owned and third party-owned infrastructure;
- security threats such as military campaigns, terrorist attacks, and cybersecurity breaches, against, or otherwise impacting, our facilities and systems;
- our ability to purchase propane from our suppliers and make associated profitable sales transactions for our wholesale propane logistics business;
- our ability to obtain insurance on commercially reasonable terms, if at all, as well as the adequacy of insurance to cover our losses; and

- the amount of natural gas we gather, compress, treat, process, transport, store and sell, or the NGLs we produce, fractionate, transport, store and sell, may be reduced if the pipelines and storage and fractionation facilities to which we deliver the natural gas or NGLs are capacity constrained and cannot, or will not, accept the natural gas or NGLs.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than we have described. The forward-looking statements in this report speak as of the filing date of this report. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by applicable securities laws.

PART I

This filing includes information for the registrant both prior to the consummation of the Transaction described below and subsequent to the consummation of the Transaction. As further described below, following completion of the Transaction on January 1, 2017, the name of the registrant was changed from DCP Midstream Partners, LP to DCP Midstream, LP on January 11, 2017 (the “Name Change”). Unless the context clearly indicates otherwise, references in this report to “we”, “our”, “us” the “registrant”or the “partnership” refers to DCP Midstream, LP and its consolidated subsidiar (i) before the consummation of the Transaction with respect to historical information including, but not limited to, operating data, operating segments, and results of operations and (ii) after the consummation of the Transaction with respect to current and forward-looking information.

Item 1. Business

OUR PARTNERSHIP

We are a Delaware limited partnership formed in 2005 by DCP Midstream, LLC to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. We are currently engaged in the business of gathering, compressing, treating, processing, transporting, storing and selling natural gas; producing, fractionating, transporting, storing and selling NGLs and recovering and selling condensate; and transporting, storing and selling propane in wholesale markets. DCP Midstream, LLC and its subsidiaries and affiliates, collectively referred to as DCP Midstream, LLC is owned 50% by
Phillips 66 and 50% by Spectra Energy Corp and its affiliates, or Spectra Energy. During the third quarter of 2016, Spectra Energy entered into an Agreement and Plan of Merger (the "Merger Agreement") with Enbridge Inc. ("Enbridge"), a Canadian corporation, and anticipates completing the proposed merger during the first quarter of 2017. The Merger Agreement provides that, upon closing of the proposed merger, Spectra Energy will continue its separate corporate existence as a wholly owned subsidiary of Enbridge.

On December 30, 2016, the partnership entered into a Contribution Agreement with DCP Midstream, LLC and DCP Midstream Operating, LP (the “Operating Partnership”), a wholly owned subsidiary of the partnership. On January 1, 2017, DCP Midstream, LLC contributed to us: (i) its ownership interests in all of its subsidiaries owning operating assets, and (ii) $424 million of cash (together the “Contributions”). In consideration of the partnership’s receipt of the Contributions, (i) the partnership issued 28,552,480 common units to DCP Midstream, LLC and 2,550,644 general partner units to DCP Midstream GP, LP, the General Partner in a private placement and (ii) the Operating Partnership assumed $3,150 million of DCP Midstream, LLC’s debt. The transactions and documents contemplated by the Contribution Agreement are collectively referred to as the “Transaction”.

OVERVIEW, STRATEGIES AND COMPETITIVE STRENGTHS

This section reflects our business strategies following the Transaction

Our Business

Following the Transaction, we became one of the largest gatherers of natural gas, based on wellhead volumes, in the United States, and became the largest producer and marketer of NGLs in the United States. In 2016, we gathered, processed and transported an average of approximately 6.5 trillion Btus per day of natural gas and produced an average of approximately 393,000 barrels per day of NGLs. Our primary operations consist of:

- gathering, compressing, treating, processing natural gas and producing and fractionating NGLs; and
- logistics and marketing, from which we generate revenues primarily by trading, transporting, storing and marketing natural gas and NGLs, fractionating NGLs, and recovering and selling condensate.

The diagram below depicts our organizational structure as of January 1, 2017 following the Transaction.

We operate in 17 states in the United States. Our gathering systems and processing plants are connected to several interstate and intrastate natural gas pipelines. We also operate various NGL pipeline systems, one NGL and one natural gas storage facility. Following the consummation of the Transaction, our gathering systems consisted of approximately 64,000 miles of gathering and transmission pipeline owned or operated by us. We receive natural gas from a diverse group of producers under contracts with varying durations, and we receive fees or commodities from the producers to transport the natural gas from the wellhead to the processing plant.

Following the consummation of the Transaction, we own or operate 61 natural gas processing plants. We also own an interest in one additional plant through our 40% equity interest in Discovery Producer Services, LLC. At some of these facilities, we fractionate NGLs into individual components (ethane, propane, butane and natural gasoline). We receive fees or commodities as payment for our natural gas processing services, depending on the types of contracts we enter into with each supplier.

We purchase or take custody of substantially all of our natural gas from producers, principally under three types of processing contracts: fee-based contracts; percent-of-proceeds/index contracts; and keep-whole and wellhead purchase arrangements.

Based on our contracts, we have a long position in NGLs, natural gas and condensate and are sensitive to changes in commodity prices. Our operations of gathering, processing, compressing, transporting and storing natural gas, and the related operations of fractionating, transporting, storing and marketing of NGLs, create commodity price risk due to market fluctuations in commodity prices, primarily with respect to the prices of NGLs, natural gas and crude oil. You should read Item 1A. Risk Factors for risks associated with our business. Our business is dependent upon commodity prices and market demand for crude oil, natural gas and NGLs, which are beyond our control and have been, and may continue to be, volatile.

Our strategies for managing this commodity exposure and the related earnings and cash flow volatility include the following:

- A significant portion of our income is generated from fee-based contracts.
- We have negotiated terms in our percent-of-proceeds and keep-whole contracts that provide us with downside protection. These terms include volume tiers, pricing floors and provisions that reduce the likelihood that we would be required to operate at an economic loss.
- We have a hedging program where we enter into derivative financial instruments to mitigate a portion of the risk of weakened natural gas, NGL and condensate prices associated with our gathering, processing and sales activities, thereby stabilizing our cash flows. The commodity derivative instruments used for our hedging program are a combination of direct NGL product, crude oil, and natural gas hedges.

We sell NGLs to a variety of customers ranging from large, multi-national petrochemical and refining companies to small regional retail propane distributors. Substantially all of our NGL sales are made at market-based prices, including approximately 27% of our NGL production which was committed to Phillips 66 and Chevron Phillips Chemical, or CPChem as of December 31, 2016, the primary production commitment of which began a ratable wind down period in December 2014 and expires in January 2019. We anticipate continuing to purchase and sell commodities with Phillips 66 and CPChem in the ordinary course of business.

We sell the residual natural gas (primarily methane) that results from processing natural gas, to marketers and end-users at market-based prices. End-users include large industrial companies, natural gas distribution companies and electric utilities. We market residue gas and NGLs through our wholly-owned marketing company. We also have storage capacity for residue gas of approximately 12 Bcf at our Spindletop natural gas storage facility.

Our Business Strategy

Our primary business objectives are to achieve sustained company profitability, a strong balance sheet and profitable growth thereby sustaining our cash distribution per unit. We intend to accomplish these objectives by prudently executing the following business strategies:

Improve Operational Performance. We believe our operating efficiency and reliability enhance our ability to attract new natural gas supplies by enabling us to offer more competitive terms, services and service flexibility to producers. We believe we have a complementary base of assets from which to further extract operating efficiencies, while continuing to provide superior customer service.

Contract Realignment. Through our contract realignment initiatives, we have grown our fee-based asset base. Under these fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, compressing, treating, processing, transporting or storing natural gas and fractionating, storing and transporting NGLs. The revenues we earn are directly related to the volume of natural gas or NGLs that flows through our systems and are not directly dependent on

commodity prices. However, to the extent a sustained decline in commodity prices results in a decline in volumes, our revenues from these arrangements would be reduced.
Targeted Growth. We intend to use our strategic asset base in the United States and our position as one of the largest gatherers of natural gas, and as the largest producer and marketer of NGLs in the United States, as a platform for future growth. We plan to grow our business by constructing new gathering lines, processing facilities and NGL pipeline infrastructure, and expanding existing infrastructure.
Pursue strategic third party acquisitions. We pursue economically attractive and strategic acquisition opportunities within the midstream energy industry, both in new and existing lines of business, and geographic areas of operation.
Our Competitive Strengths
We believe that we are well positioned to execute our business strategies and achieve one of our primary business objectives of sustaining our cash distribution per unit because of the following competitive strengths:
Strategically Located Gas Gathering and Processing Operations. Our assets are strategically located in areas with the potential for increasing our volume throughput and cash flow generation. We have operations in some of the largest natural gas producing regions in the United States: Permian Basin, Rocky Mountains, Midcontinent, Gulf Coast, East Texas, South Texas, Central Texas, and Antrim Shale. In addition, we operate one of the largest portfolios of natural gas processing plants in the United States. We provide an integrated package of logistics and marketing services to natural gas producers. We believe our ability to provide all of these services gives us an advantage in competing for new supplies of natural gas because we can provide substantially all services that producers, marketers and others require to move natural gas and NGLs from wellhead to market on a cost-effective basis. Our gathering systems and processing plants are connected to several natural gas pipeline systems.
Integrated Logistics and Marketing Operations. We have connected our gathering and processing operations with more than 4,600 miles of NGL pipelines. This infrastructure offers our customers a competitive, integrated midstream service. We have strategically located NGL transportation pipelines in the Midcontinent, Rocky Mountains, East Texas, Gulf Coast, South Texas, Central Texas, and Permian Basin which are major NGL producing regions, NGL fractionation facilities in the Gulf Coast and an NGL storage facility in Michigan. Our NGL pipelines connect to various natural gas processing plants and transport the NGLs to large fractionation facilities, a petrochemical plant, a third party underground NGL storage facility and other markets along the Gulf Coast. Our NGL storage facility in Michigan is strategically adjacent to the Sarnia, Canada refinery and petrochemical corridor. We believe the strategic location of our assets coupled with their geographic diversity and our reputation for running our business reliably and effectively, presents us with continuing opportunities to provide competitive services to our customers and attract new natural gas production.
Stable cash flows. Our operations consist of a mix of fee-based and commodity-based services, which together with our commodity hedging program, are intended to generate relatively stable cash flows. Growth in our fee-based earnings will reduce the impact of unhedged margins and allow us to continue to generate relatively stable cash flows. Additionally, while certain of our gathering and processing contracts subject us to commodity price risk, we have mitigated a portion of our currently anticipated commodity price risk associated with the equity volumes from our gathering and processing operations with fixed price commodity swaps, settling through the first quarter of 2018.
Established Relationships with Oil, Natural Gas and Petrochemical Companies. We have long-term relationships with many of our suppliers and customers, and we expect that we will continue to benefit from these relationships.
Experienced Management Team. Our senior management team and board of directors have extensive experience in the midstream industry. We believe our management team has a proven track record of enhancing value through organic growth and the acquisition, optimization and integration of midstream assets.
Affiliation with DCP Midstream, LLC and its owners. Our relationship with DCP Midstream, LLC and its owners, Phillips 66 and Spectra Energy, should continue to provide us with significant business opportunities. Through our relationship with DCP Midstream, LLC and its owners, we believe our strong commercial relationships throughout the energy industry, including with major producers of natural gas and NGLs in the United States, will help facilitate the implementation of our strategies.
DCP Midstream, LLC has a significant interest in us through its ownership of an approximately 2% general partner interest, a 36% limited partner interest and all of our incentive distribution rights.

Midstream Natural Gas Industry Overview (Natural Gas Services and Logistics and Marketing)
General
The midstream natural gas industry is the link between exploration and production of natural gas and the delivery of its components to end-use markets, and consists of the gathering, compressing, treating, processing, transporting, storing and selling of natural gas, and producing, fractionating, transporting, storing and selling NGLs.
Once natural gas is produced from wells, producers then seek to deliver the natural gas and its components to end-use markets. The following diagram illustrates the natural gas gathering, processing, fractionation, storage and transportation process, which ultimately results in natural gas and its components being delivered to end-users.
Natural Gas Gathering
The natural gas gathering process begins with the drilling of wells into gas-bearing rock formations. Once the well is completed, the well is connected to a gathering system. Onshore gathering systems generally consist of a network of small diameter pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission.
Natural Gas Compression
Gathering systems are generally operated at design pressures that will maximize the total throughput from all connected wells. Since wells produce at progressively lower field pressures as they deplete, it becomes increasingly difficult to deliver the remaining lower pressure production from the well against the prevailing gathering system pressures. Natural gas compression is a mechanical process in which a volume of wellhead gas is compressed to a desired higher pressure, allowing gas to flow into a higher pressure downstream pipeline to be brought to market. Field compression is typically used to lower the pressure of a gathering system or to provide sufficient pressure to deliver gas into a higher pressure downstream pipeline. If field compression is not installed, then the remaining natural gas in the ground will not be produced because it cannot overcome the higher gathering system pressure. In contrast, if field compression is installed, then a well can continue delivering production that otherwise would not be produced.

Natural Gas Processing

The principal component of natural gas is methane, but most natural gas produced at the wellhead also contains varying amounts of NGLs including ethane, propane, normal butane, isobutane and natural gasoline. NGLs have economic value and are utilized as a feedstock in the petrochemical and oil refining industries or directly as heating, engine or industrial fuels. Long-haul natural gas pipelines have residue natural gas specifications as to the maximum NGL content of the gas to be shipped. In order to meet quality standards for long-haul pipeline transportation, natural gas collected at the wellhead through a gathering system may need to be processed to separate hydrocarbon liquids from the natural gas that may have higher values as NGLs. NGLs are typically recovered by cooling the natural gas until the NGLs become separated through condensation. Cryogenic recovery methods are processes where this is accomplished at temperatures lower than negative 150°F. These methods provide higher NGL recovery yields.

In addition to NGLs, natural gas collected at the wellhead through a gathering system may also contain impurities, such as water, sulfur compounds, nitrogen or helium, which must also be removed to meet the quality standards for long-haul pipeline transportation. As a result, gathering systems and natural gas processing plants will typically provide ancillary services prior to processing such as dehydration, treating to remove impurities and condensate separation. Dehydration removes water from the natural gas stream, which can form ice when combined with natural gas and cause corrosion when combined with carbon dioxide or hydrogen sulfide. Natural gas with a carbon dioxide or hydrogen sulfide content higher than permitted by pipeline quality standards requires treatment with chemicals called amines at a separate treatment plant prior to processing. Condensate separation involves the removal of liquefied hydrocarbons from the natural gas stream. Once the condensate has been removed, it may be stabilized for transportation away from the processing plant via truck, rail, or pipeline.

Natural Gas and NGL Transportation and Storage

After gas collected through a gathering system is processed to meet quality standards required for transportation and NGLs have been extracted from natural gas, the residue natural gas is shipped on long-haul pipelines or injected into storage facilities. The NGLs are typically transported via NGL pipelines or trucks to a fractionator for separation of the NGLs into their individual components. Natural gas and NGLs may be held in storage facilities to meet future seasonal and customer demands. Storage facilities can include marine, pipeline and rail terminals, and underground facilities consisting of salt caverns and aquifers used for storage of natural gas and various liquefied petroleum gas products including propane, mixed butane, and normal butane. Rail, truck and pipeline connections provide varying ways of transporting natural gas and NGLs to and from storage facilities.

Natural Gas Asset Based Trading and Marketing

Natural gas storage and pipeline assets are exposed to certain risks including changes in commodity prices. Commodity price risk related to gas storage and pipeline assets can be managed through commodity derivative hedging programs. The commercial activities related to gas storage and pipeline assets primarily consist of the purchase and sale of natural gas and associated time spreads and basis spreads. A time spread transaction is executed by establishing a long gas position at one point in time and establishing an equal short gas position at a different point in time. Time spread transactions allow a locked in margin supported by the injection, withdrawal, and storage capacity of natural gas storage assets. Basis spread transactions are executed to mitigate the risk of sale and purchase price differentials across a system. A basis spread transaction allows a locked in margin on physical purchases and sales of gas, including injections and withdrawals from storage. Swaps may be used to execute these transactions.

NGL Trading

NGL trading activity includes trading energy related products and services through the use of fixed forward sales and purchases, basis and spread trades, storage opportunities, put/call options, term contracts and spot market trading. These energy trading operations are exposed to market variables and commodity price risk with respect to these products and services, and these operations may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments.

Wholesale Propane Logistics

Wholesale propane logistics covers the receipt of propane from processing plants, fractionation facilities and crude oil refineries, the transportation of that propane by pipeline, rail or ship to terminals and storage facilities, the storage of propane
and the delivery of propane to distributors. Propane is extracted from the natural gas stream at processing plants, separated from NGLs at fractionation facilities or separated from crude oil during the refining process. Propane demand is typically highest in

6

suburban and rural areas where natural gas is not readily available, such as the Northeastern United States. Propane demand is typically highest in the winter heating season months of October through April.

OUR OPERATING SEGMENTS

The following sections reflect our Natural Gas Services, NGL Logistics and Wholesale Propane Logistics business segments prior to the Transaction and are intended to provide operating context for the financial results for the year ended December 31, 2016 provided elsewhere in this Annual Report.

Our operations are organized into three business segments: Natural Gas Services, NGL Logistics and Wholesale Propane Logistics. A map representing the geographic location and type of our assets for each of these segments is set forth below. Additional maps detailing the individual assets can be found on our website at www.dcpmidstream.com. Our website and the information contained on that site, or connected to that site, are not incorporated by reference into this report.

Natural Gas Services Segment

General

Our Natural Gas Services segment consists of a geographically diverse complement of assets and ownership interests that provide a varied array of wellhead to market services for our producer customers. These services include gathering, compressing, treating, processing, transporting and storing natural gas, and fractionating NGLs. These assets are positioned in certain areas with active drilling programs and opportunities for organic growth. Our Natural Gas Services segment owns or operates assets in seven states in the continental United States: Arkansas, Colorado, Louisiana, Michigan, Oklahoma, Texas and Wyoming. The assets in these states include our Eagle Ford system, our East Texas system, our DJ Basin system, our 40% limited liability company interest in the Discovery system located offshore and onshore in Southern Louisiana, our Southeast Texas system, our Michigan system, our Southern Oklahoma system, our Wyoming system, and our 75% operating interest in the Piceance system. This geographic diversity helps to mitigate our natural gas supply risk in that we are not tied to one natural gas resource type or producing area. We believe our current geographic mix of assets will be an important factor for maintaining overall volumes and cash flow for this segment.

During 2016, the volume throughput on our assets was in excess of 2.4 Bcf/d, originating from a diversified mix of customers. Our systems each have significant customer acreage dedications that will continue to provide opportunities for growth as those customers execute their drilling plans over time. Our gathering systems also attract new natural gas volumes through numerous smaller acreage dedications and also by contracting with undedicated producers who are operating in or around our gathering footprint. During 2016, the combined NGL production from our processing facilities was approximately 155,000 Bbls/d and was delivered and sold into various NGL takeaway pipelines or transported by truck.

Our natural gas systems have the ability to deliver gas into numerous downstream transportation pipelines and markets. Many of our outlets transport gas to premium markets in the eastern United States, further enhancing the competitiveness of our commercial efforts in and around our natural gas gathering systems.

Gathering and Transmission Systems, Plants, Fractionators and Storage Facilities

The following is operating data for our systems prior to the Transaction:

2016 Operating Data

System	Ownership Interest	Plants	Approximate Gas Gathering and Transmission Systems (Miles)	Fractionators	Approximate Net Nameplate Plant Capacity (MMcf/d) (a)	Approximate Natural Gas Storage Capacity (Bcf)	Natural Gas Throughput (MMcf/d) (a)	NGL Production (Bbls/d) (a)
Eagle Ford	100%	7(c)	5,490	3	1,175	—	753	65,680
East Texas	100%	3(c)	840	1	860	—	468	22,824
DJ Basin	100%	3(c)	—	—	395	—	395	47,162
Discovery (b)	40%	1(c)	560	1	240	—	228	7,892
Other	Various	7(c)	2,810	—	888	12	605	11,401
Total		21	9,700	5	3,558	12	2,449	154,959

(a) Represents total capacity or total volumes allocated to our proportionate ownership share for 2016 divided by 365 days.

(b) Represents an asset operated by a third party.

(c) Represents NGL extraction plants and the associated processing capacity.

Our Eagle Ford system is a fully integrated midstream business in Fayette, Goliad, Jackson, Jim Wells, Lavaca, Live Oak and Nueces counties in Texas which includes gathering systems, production from 900,000 acres supported by acreage dedications or throughput commitments under long-term predominantly percent-of-proceeds agreements, cryogenic natural gas processing plants and fractionation facilities.

Our East Texas system located near Carthage, Texas, includes a natural gas processing complex that is connected to its gathering system, as well as third party gathering systems, which gathers, transports, compresses, treats and processes natural gas and NGLs. Our East Texas facility may also fractionate NGLs, which can be marketed at nearby petrochemical facilities.

Our DJ Basin system consists of three gas processing plants in the Denver-Julesburg Basin, or DJ Basin, in Weld County, Colorado. Our DJ Basin system also connects to DCP Midstream, LLC plants and gathering systems and delivers NGLs to the Wattenberg, Front Range and Texas Express pipelines in our NGL Logistics segment. In the first quarter of 2016, we completed construction on our Grand Parkway gathering system.

We have a 40% interest in Discovery Producer Services LLC, or Discovery, with the remaining 60% owned by Williams Partners L.P. The Discovery system is operated by Williams Partners L.P. and offers a full range of wellhead-to-market services to both onshore and offshore natural gas producers. The assets are primarily located in the eastern Gulf of Mexico and Lafourche Parish, Louisiana. The Keathley Canyon Connector extension, is supported by long-term fee-based agreements with the Lucius and Hadrian South owners, as well as the Heidelberg and Hadrian North owners, for natural gas gathering, transportation and processing services for production from those fields. In addition, the pipeline system is in proximity to other high-potential deepwater Gulf of Mexico discoveries and prospects.

The following systems are included in Other:

- Our Southeast Texas system;
- Our Michigan system;
- The Northern Louisiana system which was sold on July 1, 2016, and included in the 2016 operating data through the period of ownership;
- Our Southern Oklahoma system;
- Our Wyoming system; and
- Our 75% interest in our Piceance system.

Natural Gas and NGL Markets

The Eagle Ford system has natural gas residue outlets including interstate and intrastate pipelines. The system delivers NGLs to the Gulf Coast petrochemical markets and to Mont Belvieu through our Sand Hills pipeline, owned approximately one-third each by us, DCP Midstream, LLC and Phillips 66, and other third party NGL pipelines. Our Eagle plant has delivery options into the Trunkline and Transco gas pipeline systems.

The East Texas system delivers gas primarily through its Carthage Hub which delivers residue gas to multiple interstate and intrastate pipelines. Certain of the lighter NGLs, consisting of ethane and propane, are fractionated at the East Texas facility and sold to regional petrochemical purchasers. The remaining NGLs, including butanes and natural gasoline, are purchased by DCP Midstream, LLC and transported to Mont Belvieu for fractionation and sale.

The DJ Basin system delivers to the Conway hub in Bushton, Kansas via our Wattenberg pipeline and to the Mont Belvieu hub in Mont Belvieu, Texas via the Front Range and Texas Express pipelines in our NGL Logistics segment.

The Discovery assets have access to downstream pipelines and markets. The NGLs are fractionated, then delivered downstream to third-party purchasers consisting of a mix of local petrochemical facilities and wholesale distribution companies as well as pipelines that transport product to the storage and distribution center near Napoleonville, Louisiana or other similar product hubs.

Customers and Contracts

The suppliers of natural gas to our Natural Gas Services segment are a broad cross-section of the natural gas producing community. We actively seek new producing customers of natural gas on all of our systems to increase throughput volume and to offset natural declines in the production from connected wells. We obtain new natural gas supplies in our operating areas by contracting for production from new wells, by connecting new wells drilled on dedicated acreage and by obtaining natural gas that has been directly received or released from other gathering systems.

Our contracts with our producing customers in our Natural Gas Services segment are a mix of commodity sensitive percent-of-proceeds and percent-of-liquids contracts and non-commodity sensitive fee-based contracts. Our gross margin generated from percent-of-proceeds contracts is directly related to the price of natural gas, NGLs and condensate and our gross margin generated from percent-of-liquids contracts is directly related to the price of NGLs and condensate. Additionally, these contracts may include fee-based components. Generally, the initial term of these purchase agreements is for three to five years or, in some cases, the life of the lease. As we negotiate new agreements and renegotiate existing agreements, this may result in a change in contract mix period over period. The largest percentage of volume at our Southern Oklahoma and Eagle Ford systems are processed under percent-of-proceeds contracts. The producer contracts at our East Texas and Southeast Texas systems are a combination of percent-of-proceeds and fee-based contracts. The majority of the contracts for our Piceance, DJ Basin and Michigan systems are fee-based. The DJ Basin system has in place a long-term fee-based processing agreement with DCP Midstream, LLC which provides us with a fixed demand charge on a portion of the plants' capacities and a throughput fee on all volumes processed. Our Wyoming system has a combination of percent-of-proceeds and fee-based contracts. Discovery has percent-of-liquids, fee-based and keep-whole contracts.

Discovery’s 100% owned subsidiary, Discovery Gas Transmission, owns the mainline and the Federal Energy Regulatory Commission, or FERC, regulated laterals, which generate revenues through a tariff on file with FERC for several types of service: traditional firm transportation service with reservation fees; firm transportation service on a commodity basis with reserve dedication; and interruptible transportation service. In addition, for any of these general services, Discovery Gas

Transmission has the authority to negotiate a specific rate arrangement with an individual shipper and has several of these arrangements currently in effect.

Competition

The natural gas services business is highly competitive in our markets and includes major integrated oil and gas companies, interstate and intrastate pipelines, and companies that gather, compress, treat, process, transport, store and/or market natural gas. Competition is often the greatest in geographic areas experiencing robust drilling by producers and during periods of high commodity prices for crude oil, natural gas and/or NGLs. Competition is also increased in those geographic areas where our commercial contracts with our customers are shorter term and therefore must be renegotiated on a more frequent basis.

NGL Logistics Segment

General

We own and operate assets for our NGL Logistics business in the states of Colorado, Kansas, Louisiana, Michigan, Oklahoma and Texas, which are major NGL producing regions.

Our NGL pipelines transport NGLs from natural gas processing plants to fractionation facilities, a petrochemical plant and a third party underground NGL storage facility. Our pipelines provide transportation services to customers primarily on a fee basis. Therefore, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers. The volumes of NGLs transported on our pipelines are dependent on the level of production of NGLs from processing plants connected to our NGL pipelines. When natural gas prices are high relative to NGL prices, it is less profitable to recover NGLs from natural gas because of the higher value of natural gas compared to the value of NGLs. As a result, we have experienced periods, and will likely experience periods in the future, when higher relative natural gas prices reduce the volume of NGLs produced at plants connected to our NGL pipelines.

Our NGL fractionation facilities in the DJ Basin, in Colorado, and our partially owned facilities in Mont Belvieu, Texas, separate NGLs received from processing plants into their individual components. The fractionation facilities provide services on a fee basis. Therefore, the results of operations for this business are generally dependent upon the volume of NGLs fractionated and the level of fees charged to customers.

Our NGL storage facility is located in Marysville, Michigan with strategic access to the Marcellus, Utica and Canadian NGLs. Our facility serves regional refining and petrochemical demand, and helps to balance the seasonality of propane distribution in the Midwestern and Northeastern United States and in Sarnia, Canada. We provide services to customers primarily on a fee basis. Therefore, the results of operations for this business are generally dependent upon the volume of product injected, stored and withdrawn, and the level of fees charged to customers.

The following is operating data for our NGL Logistics segment prior to the Transaction:

2016 Operating Data

System	Ownership Interest	Approximate System Length (Miles)	Fractionators	Approximate Throughput Capacity (MBbls/d) (a)	Approximate NGL Storage Capacity (MMBbls) (a)	Pipeline Throughput (MBbls/d) (a)	Fractionator Throughput (MBbls/d) (a)
Sand Hills pipeline	33.33%	1,160	—	83	—	79	—
Southern Hills pipeline	33.33%	940	—	58	—	32	—
Texas Express pipeline (b)	10%	595	—	28	—	15	—
Wattenberg pipeline	100%	470	—	22	—	20	—
Front Range pipeline (b)	33.33%	450	—	50	—	34	—
Black Lake pipeline	100%	315	—	80	—	55	—
Panola pipeline (b)	15%	185	—	8	—	8	—
Other pipelines (c)	100%	135	—	62	—	46	—
Mont Belvieu Enterprise fractionator (b)	12.5%	—	1	28	—	—	28
Mont Belvieu 1 fractionator (b)	20%	—	1	32	—	—	21
DJ Basin fractionators	100%	—	2	15	—	—	11
Marysville storage facility	100%	—	—	—	8	—	—
Total		4,250	4	466	8	289	60

(a) Represents total capacity or throughput allocated to our proportionate ownership share for 2016 divided by 365 days.

(b) Represents an asset operated by a third party.

(c) Includes our 100% interest in Seabreeze, Wilbreeze and other NGL pipelines.

NGL Pipelines

DCP Sand Hills Pipeline, LLC, or the Sand Hills pipeline, an interstate NGL pipeline in which we owned a 33.33% interest in 2016, and following the Transaction, we now own a 66.67% interest and operate the pipeline, which is a common carrier pipeline which provides takeaway service from plants in the Permian and the Eagle Ford basins to fractionation facilities along the Texas Gulf Coast and at the Mont Belvieu, Texas market hub.

13

DCP Southern Hills Pipeline, LLC, or the Southern Hills pipeline, an interstate NGL pipeline in which we owned a 33.33% interest in 2016, and following the Transaction, we now own a 66.67% interest and operate the pipeline, which provides takeaway service from the Midcontinent to fractionation facilities at the Mont Belvieu, Texas market hub.
Texas Express Pipeline LLC, or the Texas Express pipeline, an intrastate NGL pipeline in which we own a 10% interest, originates near Skellytown in Carson County, Texas, and extends to Enterprise Products Partners L.P.'s, or Enterprise, natural gas liquids fractionation and storage complex at Mont Belvieu, Texas. The pipeline also provides access to other third party facilities in the area. Enterprise is the operator of the pipeline.
The Wattenberg interstate NGL pipeline originates in the DJ Basin in Colorado and terminates near the Conway hub in Bushton, Kansas. The pipeline is connected to plants we acquired from DCP Midstream, LLC in the Transaction and our O'Connor plant in the DJ Basin.
Front Range Pipeline LLC, or the Front Range pipeline, an interstate NGL pipeline in which we own a 33.33% interest, is a raw NGL mix pipeline that originates in the DJ Basin and extends to Skellytown, Texas. The Front Range pipeline connects to the O'Connor plant, Lucerne 1 plant and the Lucerne 2 plant, plants owned by DCP Midstream, LLC prior to the Transaction, and third party plants in the DJ Basin. Enterprise is the operator of the pipeline.
The Black Lake interstate NGL pipeline originates in northwestern Louisiana and terminates in Mont Belvieu, Texas. Black Lake receives NGLs from gas processing plants in northwestern Louisiana and southeastern Texas, including multiple third party plants, the Sand Hills pipeline and a third party storage facility. Black Lake delivers the NGLs it receives from these sources to fractionation plants in Mont Belvieu, Texas including our partially owned Enterprise and Mont Belvieu 1 fractionators as well as third party pipelines.
Panola Pipeline Company, LLC, or the Panola pipeline, an intrastate NGL pipeline in which we own a 15% interest, is an approximately 180-mile NGL pipeline system extending from points near Carthage, Texas to Mont Belvieu, Texas. Enterprise is the operator of the pipeline.

NGL Fractionation Facilities

We own a 12.5% interest in the Enterprise fractionator operated by Enterprise and a 20% interest in the Mont Belvieu 1 fractionator operated by ONEOK Partners, both located in Mont Belvieu, Texas.
Our DJ Basin NGL fractionators in Colorado are located on processing plant sites that were owned and operated by DCP Midstream, LLC, prior to the Transaction, which delivers NGLs to the fractionators under a long-term fractionation agreement.

NGL Storage Facility

Our NGL storage facility is located in Marysville, Michigan and includes 11 underground salt caverns with approximately 8 MMBbls of storage capacity and rail, truck and pipeline connections providing an important supply point for refiners, petrochemical plants and wholesale propane distributors in the Sarnia, midwestern and northeastern markets.

Customers and Contracts

Our contracts with our customers in our NGL Logistics segment are primarily fee-based contracts.
In 2016, the Southern Hills, Sand Hills, Texas Express, and Front Range pipelines had long-term, fee-based, ship-or-pay transportation agreements in place with affiliates of DCP Midstream, LLC as well as third party shippers. These NGL pipelines collect fee-based transportation revenue under regulated tariffs.
The Wattenberg pipeline is an open access pipeline with access to numerous gas processing facilities in the DJ Basin. Prior to the Transaction, the Wattenberg pipeline was supported by a long-term dedication and transportation agreement with a subsidiary of DCP Midstream, LLC whereby certain NGL volumes produced at several of DCP Midstream, LLC’s processing facilities were dedicated for transportation on the Wattenberg pipeline. We collect fee-based transportation revenue under our tariff.
DCP Midstream, LLC has historically been the largest active shipper on the Black Lake pipeline, accounting for approximately 66% of total throughput in 2016. The Black Lake pipeline generates revenue primarily through a FERC-regulated tariff.
DCP Midstream, LLC supplied certain committed NGLs to our DJ Basin NGL fractionators under fee-based agreements.

Our Marysville NGL storage facility serves wholesale propane customers, as well as refining and petrochemical customers, under one to three-year term storage agreements. Our revenues for this facility are primarily fee-based.

Competition

The NGL logistics business is highly competitive in our markets and includes interstate and intrastate pipelines, integrated oil and gas companies that produce, fractionate, transport, store and sell NGLs, and underground storage facilities. Competition is often the greatest in geographic areas experiencing robust drilling by producers and strong petrochemical demand and during periods of high NGL prices relative to natural gas. Competition is also increased in those geographic areas where our contracts with our customers are shorter term and therefore must be renegotiated on a more frequent basis.

Wholesale Propane Logistics Segment

General

We own or operate assets for our wholesale propane logistics business in the states of Maine, Massachusetts, New York, Pennsylvania, Vermont and Virginia. Our operations serve the large propane and other liquefied petroleum gas markets in the Northeastern, mid-Atlantic, and upper Midwestern states.

Due to our multiple propane supply sources, annual and long-term propane supply purchase arrangements, storage capabilities, and multiple terminal locations for wholesale propane delivery, we are generally able to provide our propane distribution customers with reliable, low cost deliveries and greater volumes of propane during periods of tight supply such as the winter months. We may also provide storage services to our customers for propane and other liquefied petroleum gases. We believe these factors generally result in our maintaining favorable relationships with our customers and allowing us to remain a supplier to many of the large distributors in the Northeastern and Mid-Atlantic United States. As a result, we serve as the baseload provider of propane supply to many of our propane distribution customers.

Pipeline deliveries to the Northeastern and Mid-Atlantic markets in the winter season are generally at capacity and competing pipeline-dependent terminals can have supply constraints or outages during peak market conditions. Our system of terminals has excess capacity, which provides us with opportunities to increase our volumes with minimal additional cost.

Our Terminals

Our operations include one owned marine terminal, one owned propane pipeline terminal and six owned propane rail terminals, with a combined capacity of approximately 550 MBbls, and access to several open access pipeline terminals. Our owned marine terminal also has storage capabilities for other liquefied petroleum gases. We own our rail terminals and lease the land on which the terminals are situated under long-term leases, except for the York terminal where we own the land. Each of our rail terminals consist of two to three propane tanks that provide additional capacity for storage, and two high volume racks for loading propane into trucks.

Propane Supply

Our wholesale propane business has a strategic network of supply arrangements under annual and multi-year agreements with index-based pricing. The remaining supply is purchased on month-to-month terms to match our anticipated sale requirements. Our primary suppliers of propane include a subsidiary of DCP Midstream, LLC, and MarkWest. We may also obtain supply from our NGL storage facility in Marysville, Michigan.

For our rail terminals, we contract for propane at various major supply points in the United States and Canada, and transport the product to our terminals under long-term rail commitments, which provide fixed transportation costs that are subject to prevailing fuel surcharges. We also purchase propane supply from natural gas fractionation plants and crude oil refineries located in the Texas and Louisiana Gulf Coast. Through this process, we take custody of the propane and either sell it in the wholesale market or store it at our facilities.

Based on the carrying value of our inventory, timing of inventory transactions and the volatility of the market value of propane, we have historically and may periodically recognize non-cash lower of cost or market inventory adjustments, which occur when the market value of our commodities declines below our carrying value.

Customers and Contracts

We typically sell propane to propane distributors under annual sales agreements, negotiated each spring, that specify floating price terms that provide us a margin in excess of our floating index-based supply costs under our supply purchase arrangements. In the event that a propane distributor desires to purchase propane from us on a fixed price basis, we may enter into fixed price sales agreements with terms of generally up to one year. We manage this commodity price risk by purchasing and storing propane, entering into physical purchase agreements or entering into offsetting financial derivative instruments with third parties that generally match the quantities of propane subject to these fixed price sales agreements. We believe that our ability to help our clients manage their commodity price exposure by offering propane at a fixed price may lead to improved margins and a larger customer base. We provide storage services for other liquefied petroleum gases on a fee basis under a multi-year agreement. Historically, the majority of the gross margin generated by our wholesale propane business is earned in the heating season months of October through April, which corresponds to the general market demand for propane.

We had two third-party customers in our Wholesale Propane segment that accounted for greater than 10% of our segment revenues for the year ended December 31, 2016.

Competition
The wholesale propane business is highly competitive in the mid-Atlantic, upper Midwestern and Northeastern regions of the United States. Our wholesale propane business' competitors include integrated oil and gas and energy companies, interstate and intrastate pipelines, as well as marketers and other wholesalers.
Other Segment Information
For additional information on our segments, please see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations," and Note 19 of the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data."
We have no revenue attributable to international activities.
REGULATORY AND ENVIRONMENTAL MATTERS
The following section reflects our Regulatory and Environmental Matters existing subsequent to the Transaction
Safety and Maintenance Regulation
We are subject to regulation by the United States Department of Transportation, or DOT, under the Hazardous Liquids Pipeline Safety Act of 1979, as amended, or HLPSA, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of pipeline facilities. HLPSA applies to interstate and intrastate pipeline facilities and the pipeline transportation of liquid petroleum and petroleum products, including NGLs and condensate, and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the United States Secretary of Transportation. These regulations include potential fines and penalties for violations. We believe that we are in compliance in all material respects with these HLPSA regulations.
We are also subject to the Natural Gas Pipeline Safety Act of 1968, as amended, or NGPSA, and the Pipeline Safety Improvement Act of 2002. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities while the Pipeline Safety Improvement Act establishes mandatory inspections for all United States oil and natural gas transportation pipelines in high-consequence areas within 10 years. DOT, through the Pipeline and Hazardous Materials Safety Administration (PHMSA), has developed regulations implementing the Pipeline Safety Improvement Act that requires pipeline operators to implement integrity management programs, including more frequent inspections and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property.
Pipeline safety legislation enacted in 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, (the Pipeline Safety and Job Creations Act) reauthorizes funding for federal pipeline safety programs through 2015, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines, including the expansion of integrity management, use of automatic and remote-controlled shut-off valves, leak detection systems, sufficiency of existing regulation of gathering pipelines, use of excess flow valves, verification of maximum allowable operating pressure, incident notification, and other pipeline-safety related requirements. New rules proposed by DOT's PHMSA address many areas of this legislation. Extending the integrity management requirements to our gathering lines would impose additional obligations on us and could add material cost to our operations.
The Pipeline Safety and Job Creation Act requires more stringent oversight of pipelines and increased civil penalties for violations of pipeline safety rules. The legislation gives PHMSA civil penalty authority up to $200,000 per day per violation, with a maximum of $2 million for any related series of violations. Any material penalties or fines under these or other statutes, rules, regulations or orders could have a material adverse impact on our business, financial condition, results of operation and cash flows.
We currently estimate we will incur between $16 million and $20 million between 2017 and 2021 to implement integrity management program testing along certain segments of our natural gas transmission and NGL pipelines. We believe that we are in compliance in all material respects with the NGPSA and the Pipeline Safety Improvement Act of 2002 and the Pipeline Safety and Job Creation Act.
States are largely preempted by federal law from regulating pipeline safety but may assume responsibility for enforcing intrastate pipeline regulations at least as stringent as the federal standards. In practice, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate any significant problems

in complying with applicable state laws and regulations in those states in which we or the entities in which we own an interest operate. Our natural gas transmission and

18

regulated gathering pipelines have ongoing inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

In addition, we are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes, whose purpose is to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the Environmental Protection Agency, or EPA, community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We and the entities in which we own an interest are also subject to OSHA Process Safety Management and EPA Risk Management Program regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. The OSHA regulations apply to any process which involves a chemical at or above specified thresholds, or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks below their normal boiling point without the benefit of chilling or refrigeration are exempt from these standards. The EPA regulations have similar applicability thresholds. We have an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we are in compliance in all material respects with all applicable laws and regulations relating to worker health and safety.

Propane Regulation

National Fire Protection Association Codes No. 54 and No. 58, which establish rules and procedures governing the safe handling of propane, or comparable regulations, have been adopted as the industry standard in all of the states in which we operate. In some states these laws are administered by state agencies, and in others they are administered on a municipal level. With respect to the transportation of propane by truck, we are subject to regulations promulgated under the Federal Motor Carrier Safety Act. These regulations cover the transportation of hazardous materials and are administered by the DOT. The transportation of propane by rail is regulated by the Federal Railroad Administration. We conduct ongoing training programs to help ensure that our operations are in compliance with applicable regulations. We maintain various permits that are necessary to operate our facilities, some of which may be material to our propane operations. We believe that the procedures currently in effect at all of our facilities for the handling, storage and distribution of propane are consistent with industry standards and are in compliance in all material respects with applicable laws and regulations.

FERC and State Regulation of Operations

FERC regulation of interstate natural gas pipelines, the marketing and sale of natural gas in interstate commerce and the transportation of NGLs in interstate commerce may affect certain aspects of our business and the market for our products and services. Regulation of gathering systems and intrastate transportation of natural gas and NGLs by state agencies may also affect our business.

Interstate Natural Gas Pipeline Regulation

Our Cimarron River, Discovery, and Dauphin Island Gathering Partners systems, or portions thereof, are some of our natural gas pipeline assets that are subject to regulation by FERC, under the Natural Gas Act of 1938, as amended, or NGA. Natural gas companies subject to the NGA may only charge rates that have been determined to be just and reasonable. In addition, FERC authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce includes:

- certification and construction of new facilities;
- abandonment of services and facilities;
- maintenance of accounts and records;
- acquisition and disposition of facilities;
- initiation and discontinuation of transportation services;
- terms and conditions of transportation services and service contracts with customers;
- depreciation and amortization policies;
- conduct and relationship with certain affiliates; and
- various other matters.

19

Generally, the maximum filed recourse rates for an interstate natural gas pipeline's transportation services are based on the pipeline's cost of service including recovery of and a return on the pipeline’s actual prudent investment cost. Key determinants in the ratemaking process are costs of providing service, including an income tax allowance, allowed rate of return and volume throughput and contractual capacity commitment assumptions. The allocation of costs to various pipeline services and the manner in which rates are designed also can impact a pipeline's profitability. The maximum applicable recourse rates and terms and conditions for service are set forth in each pipeline’s FERC-approved gas tariff. FERC-regulated natural gas pipelines are permitted to discount their firm and interruptible rates without further FERC authorization down to the minimum rate or variable cost of performing service, provided they do not “unduly discriminate.”

Tariff changes can only be implemented upon approval by FERC. Two primary methods are available for changing the rates, terms and conditions of service of an interstate natural gas pipeline. Under the first method, the pipeline voluntarily seeks a tariff change by making a tariff filing with FERC justifying the proposed tariff change and providing notice, generally 30 days, to the appropriate parties. If FERC determines, as required by the NGA, that a proposed change is just and reasonable, FERC will accept the proposed change and the pipeline will implement such change in its tariff. However, if FERC determines that a proposed change may not be just and reasonable as required by NGA, then FERC may suspend such change for up to five months beyond the date on which the change would otherwise go into effect and set the matter for an administrative hearing. Subsequent to any suspension period ordered by FERC, the proposed change may be placed into effect by the company, pending final FERC approval. In most cases, a proposed rate increase is placed into effect before a final FERC determination on such rate increase, and the proposed increase is collected subject to refund (plus interest). Under the second method, FERC may, on its own motion or based on a complaint, initiate a proceeding to compel the company to change or justify its rates, terms and/or conditions of service. If FERC determines that the existing rates, terms and/or conditions of service are unjust, unreasonable, unduly discriminatory or preferential, then any rate reduction or change that it orders generally will be effective prospectively from the date of the FERC order requiring this change.

The natural gas industry historically has been heavily regulated; therefore, there is no assurance that a more stringent regulatory approach will not be pursued by FERC and Congress, especially in light of potential market power abuse by marketing companies engaged in interstate commerce. In the Energy Policy Act of 2005, or EPACT 2005, Congress amended the NGA and Federal Power Act to add anti-fraud and anti-manipulation requirements. EPACT 2005 prohibits the use of any “manipulative or deceptive device or contrivance” in connection with the purchase or sale of natural gas, electric energy or transportation subject to FERC jurisdiction. FERC adopted market manipulation and market behavior rules to implement the authority granted under EPACT 2005. These rules, which prohibit fraud and manipulation in wholesale energy markets, are subject to broad interpretation. Given FERC's broad mandate granted in EPACT 2005, if energy prices are high, or exhibit what FERC deems to be "unusual" trading patterns, FERC may investigate energy markets to determine if behavior unduly impacted or "manipulated" energy prices.

In addition, EPACT 2005 gave FERC increased penalty authority for violations of the NGA and FERC's rules and regulations thereunder. FERC may issue civil penalties of up to $1 million per day per violation, and violators may be subject to criminal penalties of up to $1 million per violation and five years in prison. FERC may also order disgorgement of profits obtained in violation of FERC rules. FERC relies on its enforcement authority in issuing a number of natural gas enforcement actions. Failure to comply with the NGA and FERC's rules and regulations thereunder could result in the imposition of civil penalties and disgorgement of profits.

Intrastate Natural Gas Pipeline Regulation

Intrastate natural gas pipeline operations are not generally subject to rate regulation by FERC, but they are subject to regulation by various agencies in the respective states where they are located. While the regulatory regime varies from state to state, state agencies typically require intrastate gas pipelines to provide service that is not unduly discriminatory and to file and/or seek approval of their rates with the agencies and permit shippers to challenge existing rates or proposed rate increases. For example, our Guadalupe system is an intrastate pipeline regulated as a gas utility by the Railroad Commission of Texas. To the extent that an intrastate pipeline system transports natural gas in interstate commerce, the rates and terms and conditions of such interstate transportation service are subject to FERC rules and regulations under Section 311 of the Natural Gas Policy Act, or NGPA. Certain of our systems are subject to FERC jurisdiction under Section 311 of the NGPA for their interstate transportation services. Section 311 regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of a local distribution company or an interstate natural gas pipeline. Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. Rates for service pursuant to Section 311 of the NGPA are generally subject to review and approval by FERC at least once every five years. Additionally, the terms and conditions of service set forth in the intrastate pipeline’s Statement of Operating Conditions are subject to FERC approval. Non-compliance with FERC's rules and regulations established under Section 311 of the NGPA, including failure to observe the service limitations applicable to transportation services provided under Section 311, failure to comply with the rates approved by FERC for Section 311 service, and failure to comply with the terms and conditions of service established in the pipeline's FERC-approved Statement of Operating Conditions could result in the imposition of civil and criminal penalties. Among other matters, EPACT 2005 also amended the NGPA to give FERC authority to impose civil penalties for violations of the NGPA up to $1 million for any one violation and violators may be subject to criminal penalties of up to $1 million per violation and five years in prison.

Gathering Pipeline Regulation

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. We believe that our natural gas gathering facilities meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services continues to be a current issue in various FERC proceedings with respect to facilities that interconnect gathering and processing plants with nearby interstate pipelines, so the classification and regulation of our gathering facilities may be subject to change based on future determinations by FERC and the courts. State regulation of gathering facilities generally includes various safety, environmental, and, in many circumstances, nondiscriminatory take requirements and complaint-based rate regulation.

Our purchasing, gathering and intrastate transportation operations are subject to ratable take and common purchaser statutes in the states in which they operate. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels where FERC has recognized a jurisdictional exemption for the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. Many of the producing states have adopted some form of complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination. Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Sales of Natural Gas

The price at which we buy and sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. However, with regard to our interstate purchases and sales of natural gas, and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the Commodity Futures Trading Commission, or CFTC. Should we violate the anti-market manipulation laws and regulations, in additional to civil and criminal penalties, we could be subject to related third party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations.

Interstate NGL Pipeline Regulation

Certain of our pipelines, including Sand Hills and Southern Hills, are common carriers that provide interstate NGL transportation services subject to FERC regulation. FERC regulates interstate common carriers under its Oil Pipeline Regulations, the Interstate Commerce Act of 1887, as amended, or ICA, and the Elkins Act of 1903, as amended. FERC requires that common carriers file tariffs containing all the rates, charges and other terms for services provided by such pipelines. The ICA requires that tariffs apply to the interstate movement of NGLs, as is the case with the Sand Hills, Southern Hills, Black Lake, Wattenberg and Front Range pipelines. Pursuant to the ICA, rates must be just, reasonable, and nondiscriminatory, and can be challenged at FERC either by protest when they are initially filed or increased or by complaint at any time they remain on file with FERC.

In October 1992, Congress passed EPACT, which among other things, required FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for pipelines regulated by FERC pursuant to the ICA. FERC responded to this mandate by issuing several orders, including Order No. 561 that enables petroleum pipelines to charge rates up to their ceiling levels, which are adjusted annually based on an inflation index. Specifically, the indexing methodology requires a pipeline to adjust the ceiling level for its rates annually by the inflation index established by the FERC. FERC reviews the indexing methodology every five years, and in 2015, the indexing methodology for the five years beginning July 1, 2016 was changed to be the Producer Price Index for Finished Goods plus 1.23 percent. The previous five-year period utilized the Producer Price Index for Finished Goods plus 2.65 percent. Pipelines may charge up to the calculated ceiling level for their transportation rates, and typically adjust their rates July 1 annually, when the new inflation index and ceiling levels are calculated. Rate increases made pursuant to the indexing methodology are subject to protest, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs from the previous year. If the indexing methodology results in a reduced ceiling level that is lower than a pipeline's filed rate, the pipeline is required to reduce its rate to comply with the lower ceiling unless doing so would reduce a rate "grandfathered" under EPACT (see below) below the grandfathered level. A pipeline must, as a general rule, utilize the indexing methodology to change its rates. FERC, however, retained cost-of-service ratemaking, market-based rates, and settlement as alternatives to the indexing approach, which alternatives may be used in certain specified circumstances. Because of the change in indexing methodology effective July 1, 2016 and the trends in the producer price index, the ceiling levels calculated for our interstate NGL pipelines may be subject to decrease, which occurred in 2016 and resulted in the decrease in the tariff rates for many such pipelines.

EPACT deemed petroleum pipeline rates in effect for the 365-day period ending on the date of enactment of EPACT that had not been subject to complaint, protest or investigation during that 365-day period to be just and reasonable under the ICA. Generally, complaints against such "grandfathered" rates may only be pursued if the complainant can show that a substantial change has occurred since the enactment of EPACT in either the economic circumstances of the petroleum pipeline, or in the nature of the services provided, that were a basis for the rate. EPACT places no such limit on challenges to a provision of a petroleum pipeline tariff as unduly discriminatory or preferential.

On October 20, 2016, FERC issued an Advance Notice of Proposed Rulemaking, which presented significant changes to the indexing mechanism and reporting requirements of common carriers subject to FERC's jurisdiction under the ICA. The proposed changes to the indexing methodology, would prohibit an increase in a common carrier's ceiling level and rates if a complaint was filed and the return as reported by the common carrier in two previous annual reports exceeded a predetermined threshold. Additionally, the FERC proposed multiple changes to its annual reporting requirements. We cannot predict the outcome of the proceeding, but the proposal, if implemented, could adversely impact future rate increases of our common carriers and place additional administration and reporting burdens on our business.

Intrastate NGL Pipeline Regulation

NGL and other common carrier petroleum pipelines that provide intrastate transportation services are subject to regulation by various agencies in the respective states where they are located. While the regulatory regime varies from state to state, state agencies typically require intrastate petroleum pipelines to file tariffs and their rates with the agencies and permit shippers to challenge existing rates or proposed rate increases. For example, certain of our pipelines have tariffs filed with the Railroad Commission of Texas for their intrastate NGL transportation services.

Environmental Matters

General

Our operation of pipelines, plants and other facilities for gathering, compressing, treating, processing, transporting, fractionating, storing or selling natural gas, NGLs and other products is subject to stringent and complex federal, state and local laws and regulations governing the emission or discharge of materials into the environment or otherwise relating to the protection of the environment.

As an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

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requiring the acquisition of permits to conduct regulated activities and imposing obligations in those permits that reduce or limit impacts to the environment;

- restricting the way we can handle or dispose of our wastes;

- limiting or prohibiting construction or operational activities in sensitive areas such as wetlands, coastal regions or areas inhabited by threatened and endangered species;
- requiring remedial action to mitigate pollution conditions caused by our operations or attributable to former operations; and
- enjoining, or compelling changes to, the operations of facilities deemed not to be in compliance with permits issued pursuant to such environmental laws and regulations.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil, or potentially criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements and the issuance of orders enjoining or affecting future operations. Certain environmental statutes impose strict liability or joint and several liability for costs required to clean up and restore sites where hazardous substances, or in some cases hydrocarbons, have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for property damage or personal injury allegedly caused by the release of substances or other waste products into the environment.

The trend in environmental regulations is to expand them, placing more restrictions and limitations on activities that may affect the environment. Thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations, participate as applicable in the public process to ensure such new requirements are well founded and reasonable or to revise them if they are not, and to manage the costs of such compliance. We also actively participate in industry groups that help formulate recommendations for addressing existing or future regulations.

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position or results of operations. Below is a discussion of the more significant environmental laws and regulations that relate to our business.

Impact of Air Quality Standards and Climate Change

A number of states have adopted or considered programs to reduce “greenhouse gases,” or GHGs, which can include methane, and, depending on the particular program or jurisdiction, we could be required to purchase and surrender allowances, either for GHG emissions resulting from our operations (e.g., compressor units) or from downstream combustion of fuels (e.g., oil or natural gas) that we process, or we may otherwise be required by regulation to take steps to reduce emissions of GHGs. Also, the EPA has declared that GHGs “endanger” public health and welfare, and is regulating GHG emissions from mobile sources such as cars and trucks. The EPA's 2010 action on the GHG vehicle emission rule triggered regulation of carbon dioxide and other GHG emissions from stationary sources under certain Clean Air Act programs at both the federal and state levels, particularly the Prevention of Significant Deterioration program and Title V permitting. These requirements for stationary sources took effect on January 2, 2011; however, in June 2014 the U.S. Supreme Court reversed a D.C. Circuit Court of Appeals decision upholding these rules and struck down the EPA’s greenhouse gas permitting rules to the extent they impose a requirement to obtain a federal air permit based solely on emissions of greenhouse gases, but major sources of other air pollutants, such as volatile organic compounds or nitrogen oxides, could still be required to implement process or technology controls and obtain permits regarding emissions of greenhouse gases. The EPA proposed a rule in 2016 to comply with the U.S. Supreme Court’s ruling by limiting the requirement to obtain permits addressing emissions of greenhouse gases to large sources of other air pollutants, such as volatile organic compounds or nitrogen oxides, which also emit 100,000 tons per year or more of CO_2 equivalent (or modifications of these sources that result in an emissions increase of 75,000 tons per year or more of CO_2). The EPA has also published various rules relating to the mandatory reporting of GHG emissions, including mandatory reporting requirements of GHGs from petroleum and natural gas systems. In October 2015, the EPA amended and expanded greenhouse gas reporting requirements to all segments of the oil and gas sector starting with the 2016 reporting year. In June 2016, the EPA published final new source performance standards for methane (a greenhouse gas) from new and modified oil and gas sector sources. These regulations expand upon the 2012 EPA rulemaking for oil and gas equipment-specific emissions controls, for example, regulating well head production emissions with leak detection and repair requirements, pneumatic controllers and pumps requirements, compressor requirements, and instituting leak detection and repair requirements for natural gas compressor and booster stations. In

October 2015, the EPA finalized a reduction of the ambient ozone standard from 75 parts per billion to 70 parts per billion under the Clean Air Act. The EPA also finalized in October 2016 Control Techniques Guidelines for emissions of volatile organic compounds from oil and gas sector sources to be implemented or utilized by states in ozone nonattainment areas, with an expected co-benefit of reduced methane emissions. The permitting, regulatory compliance and reporting programs, taken as a whole, increase the costs and complexity of oil and gas operations with potential to adversely affect the cost of doing business for our customers resulting in reduced demand for our gas processing and transportation services, and which may also require us to incur certain capital and operating expenditures in the future to meet regulatory requirements or for air pollution control equipment, for example, in connection with obtaining and maintaining operating permits and approvals for air emissions associated with our facilities and operations.

Hazardous Substances and Waste

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, or solid or hazardous wastes, including petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste, and may impose strict liability or joint and several liability for the investigation and remediation of areas at a facility where hazardous substances, or in some cases hydrocarbons, may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act, as amended, or CERCLA, also known as the Superfund law, 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 of a hazardous substance into the environment. These persons include current and prior owners or operators of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible parties the costs the agency incurs. Despite the “petroleum exclusion” of CERCLA Section 101(14), which encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, 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 into the environment.

We also generate solid wastes, including hazardous wastes that are subject to the requirements of the Resource Conservation and Recovery Act, as amended, or RCRA, and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum and natural gas production wastes are excluded from RCRA’s hazardous waste regulations. However, it is possible that these wastes, which could include wastes currently generated during our operations, may in the future be designated by the EPA as hazardous wastes and therefore be subject to more rigorous and costly disposal requirements. Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

We currently own or lease properties where petroleum hydrocarbons are being or have been handled for many years. Although we have utilized operating and disposal practices that were standard in the industry at the time, petroleum 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 other locations where these petroleum hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties may have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons or other wastes was not under our control. These properties and wastes disposed or released thereon may be subject to CERCLA, RCRA and analogous state laws, or separate state laws that address hydrocarbon releases. Under these laws, we could be required to remove or remediate releases of hydrocarbon materials, or previously disposed wastes (including wastes disposed of or released by prior owners or operators), or to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination. We are not currently aware of any facts, events or conditions relating to the application of such requirements that could reasonably have a material impact on our operations or financial condition.

Water

The Federal Water Pollution Control Act of 1972, as amended, also referred to as the Clean Water Act, or CWA, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters. Pursuant to the CWA and analogous state laws, permits must be obtained to discharge pollutants into state and federal waters. The CWA also requires implementation of spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of threshold quantities of oil or certain other materials. The CWA imposes substantial potential civil and criminal penalties for non-compliance. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities. In addition, some states maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater. The EPA has promulgated regulations that require us to have permits in order to discharge certain storm water. The EPA has entered into agreements with certain states in which we operate whereby the permits are issued and administered by the respective states. These permits may require us to monitor and sample the storm water discharges. We believe that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our financial condition or results of operations.

The Oil Pollution Act of 1990, or OPA, which is part of the Clean Water Act, addresses prevention, containment and cleanup, and liability associated with oil pollution. OPA applies to vessels, offshore platforms, and onshore facilities, including natural gas gathering and processing facilities, terminals, pipelines, and transfer facilities. OPA subjects owners of such facilities to strict liability for containment and removal costs, natural resource damages, and certain other consequences of oil spills into jurisdictional waters. Any unpermitted release of petroleum or other pollutants from our operations could result in government penalties and civil liability. We are not currently aware of any facts, events or conditions relating to the application of such requirements that could reasonably have a material impact on our operations or financial condition.

Anti-Terrorism Measures

The federal Department of Homeland Security regulates the security of chemical and industrial facilities pursuant to regulations known as the Chemical Facility Anti-Terrorism Standards. These regulations apply to oil and gas facilities, among others, that are deemed to present “high levels of security risk.” Pursuant to these regulations, certain of our facilities are required to comply with certain regulatory provisions, including requirements regarding inspections, audits, recordkeeping, and protection of chemical-terrorism vulnerability information.

Employees

We do not have any employees. Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which is managed by its general partner, DCP Midstream GP, LLC, or the General Partner, which is 100% owned by DCP Midstream, LLC. Following the consummation of the Transaction, approximately 2,650 employees of DCP Services, LLC, a wholly-owned subsidiary of DCP Midstream, LLC, provided support for our operations pursuant to the Services and Employee Secondment Agreement between DCP Services, LLC and us. For additional information, refer to “Item 10. Directors, Executive Officers and Corporate Governance” and “Item 13. Certain Relationships and Related Transactions, and Director Independence - Services Agreement” in this Annual Report on Form 10-K.

General

We make certain filings with the Securities and Exchange Commission, or 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, which are available free of charge through our website, www.dcpmidstream.com, as soon as reasonably practicable after they are filed with the SEC. The filings are also available through the SEC at the SEC’s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549 or by calling 1-800-SEC-0330. Also, these filings are available on the internet at www.sec.gov. Our annual reports to unitholders, press releases and recent analyst presentations are also available on our website. We have also posted our code of business ethics on our website.

Item 1A. Risk Factors

The following section reflects our Risk Factors existing subsequent to the Transaction

Limited partner interests are inherently different from 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. You should consider carefully the following risk factors together with all of the other information included in this Annual Report on Form 10-K in evaluating an investment in our common units.

If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially affected. In that case, we might not be able to pay the minimum quarterly distribution on our common units, the trading price of our common units could decline and you could lose all or part of your investment.

Risks Related to Our Business

Our cash flow is affected by natural gas, NGL and crude oil prices.

Our business is affected by natural gas, NGL and crude oil prices. In the past, the prices of natural gas, NGLs and crude oil have been volatile, and we expect this volatility to continue.

The level of drilling activity is dependent on economic and business factors beyond our control. Among the factors that impact drilling decisions are commodity prices, the liquids content of the natural gas production, drilling requirements for producers to hold leases, the cost of finding and producing natural gas and crude oil and the general condition of the financial markets. Commodity prices experienced significant volatility during 2016, as illustrated by the following table:

	Year Ended December 31, 2016 Daily High	Daily Low	December 31, 2016
Commodity:			
NYMEX Natural Gas ($/MMBtu)	$3.93	$1.64	$ 3.72
NGLs ($/Gallon)	$0.65	$0.30	$ 0.64
Crude Oil ($/Bbl)	$54.06	$26.21	$ 53.72

Natural gas liquids prices have softened in relation to crude prices. Natural gas and natural gas liquids prices are currently below levels seen in recent years due to increased supplies and higher inventory levels. A decline in commodity prices has resulted in a decrease in exploration and development activities in certain fields served by our gas gathering and residue gas and NGL pipeline transportation systems, and our natural gas processing and treating plants, which could lead to further reduced utilization of these assets.

During periods of natural gas price decline and/or if the price of NGLs and crude oil declines, the level of drilling activity could decrease further. When combined with a reduction of cash flow resulting from lower commodity prices, a reduction in our producers' borrowing base under reserve-based credit facilities and lack of availability of debt or equity financing for our producers may result in a significant reduction in our producers' spending for crude oil and natural gas drilling activity, which could result in lower volumes being transported on our pipeline systems. Other factors that impact production decisions include the ability of producers to obtain necessary drilling and other governmental permits and regulatory changes. Because of these factors, even if new natural gas reserves are discovered in areas served by our assets, producers may choose not to develop those reserves. If we are not able to obtain new supplies of natural gas to replace the declines resulting from reductions in drilling activity, throughput on our pipelines and the utilization rates of our treating and processing facilities would decline, which could have a material adverse effect on our business, results of operations, financial position and cash flows and our ability to make cash distributions.

Market conditions, including commodity prices, may impact our earnings, financial condition and cash flows.

The markets and prices for natural gas, NGLs, condensate and crude oil depend upon factors beyond our control and may not always have a close relationship. These factors include supply of and demand for these commodities, which fluctuate with changes in domestic and export markets and economic conditions and other factors, including:

- the level of domestic and offshore production;
- the availability of natural gas, NGLs and crude oil and the demand in the U.S. and globally for these commodities;
- a general downturn in economic conditions;
- the impact of weather, including abnormally mild winter or summer weather that cause lower energy usage for heating or cooling purposes, respectively, or extreme weather that may disrupt our operations or related upstream or downstream operations;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems and condensate and NGL export facilities;
- the availability and marketing of competitive fuels; and
- the extent of governmental regulation and taxation.

Our primary natural gas gathering and processing arrangements that expose us to commodity price risk are our percent-of-proceeds arrangements. Under percent-of-proceeds arrangements, we generally purchase natural gas from producers for an agreed percentage of the proceeds from the sale of residue gas and/or NGLs resulting from our processing activities, and then sell the resulting residue gas and NGLs at market prices. Under these types of arrangements, our revenues and our cash flows increase or decrease, whichever is applicable, as the price of natural gas and NGLs fluctuate.

Our NGL pipelines could be adversely affected by any decrease in NGL prices relative to the price of natural gas.

The profitability of our NGL pipelines is dependent on the level of production of NGLs from processing plants. When natural gas prices are high relative to NGL prices, it is less profitable to process natural gas because of the higher value of natural gas compared to the value of NGLs and because of the increased cost (principally that of natural gas as a feedstock and fuel) of separating the NGLs from the natural gas. As a result, we may experience periods in which higher natural gas prices relative to NGL prices reduce the volume of natural gas processed at plants connected to our NGL pipelines, as well as reducing the amount of NGL extraction, which would reduce the volumes and gross margins attributable to our NGL pipelines and NGL storage facilities.

Our hedging activities and the application of fair value measurements may have a material adverse effect on our earnings, profitability, cash flows, liquidity and financial condition.

We are exposed to risks associated with fluctuations in commodity prices. The extent of our commodity price risk is related largely to the effectiveness and scope of our hedging activities. For example, the derivative instruments we utilize are based on posted market prices, which may differ significantly from the actual natural gas, NGL and condensate prices that we realize in our operations. To mitigate a portion of our cash flow exposure to fluctuations in the price of natural gas and NGLs, we have entered into derivative financial instruments relating to the future price of natural gas and NGLs, as well as crude oil. If the price relationship between NGLs and crude oil declines, our commodity price risk will increase. Furthermore, we have entered into derivative transactions related to only a portion of the volume of our expected natural gas supply and production of NGLs and condensate from our processing plants; as a result, we will continue to have direct commodity price risk to the portion not covered by derivative transactions. Our actual future production may be significantly higher or lower than we estimate at the time we entered into the derivative transactions for that period. If the actual amount is higher than we estimate, we will have greater commodity price risk than we intended. If the actual amount is lower than the amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, reducing our liquidity.

We record all of our derivative financial instruments at fair value on our balance sheets primarily using information readily observable within the marketplace. In situations where market observable information is not available, we may use a variety of data points that are market observable, or in certain instances, develop our own expectation of fair value. We will continue to use market observable information as the basis for our fair value calculations; however, there is no assurance that such information will continue to be available in the future. In such instances, we may be required to exercise a higher level of judgment in developing our own expectation of fair value, which may be significantly different from the historical fair values, and may increase the volatility of our earnings.

We will continue to evaluate whether to enter into any new derivative arrangements, but there can be no assurance that we will enter into any new derivative arrangement or that our future derivative arrangements will be on terms similar to our existing derivative arrangements. Additionally, although we enter into derivative instruments to mitigate a portion of our commodity price and interest rate risk, we also forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor.

The third party counterparties to our derivative instruments may require us to post collateral in the event that our potential payment exposure exceeds a predetermined collateral threshold. Depending on the movement in commodity prices, the amount of collateral posted may increase, reducing our liquidity.

Our hedging activities may not be as effective as we intend and may actually increase the volatility of our earnings and cash flows. In addition, even though our management monitors our hedging activities, these activities can result in material losses. Such losses could occur under various circumstances, including if a counterparty does not or is unable to perform its obligations under the applicable derivative arrangement, the derivative arrangement is imperfect or ineffective, or our risk management policies and procedures are not properly followed or do not work as planned.

We could incur losses due to impairment in the carrying value of our goodwill or long-lived assets.

We periodically evaluate goodwill and long-lived assets for impairment. Our impairment analyses for long-lived assets require management to apply judgment in evaluating whether events and circumstances are present that indicate an impairment may have occurred. If we believe an impairment may have occurred judgments are then applied in estimating future cash flows as well as asset fair values, including forecasting useful lives of the assets, assessing the probability of different outcomes, and selecting the discount rate that reflects the risk inherent in future cash flows. To perform the impairment assessment for goodwill, we primarily use a discounted cash flow analysis, supplemented by a market approach analysis. 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. In estimating cash flows, we incorporate current market information (including forecasted volumes and commodity prices), as well as historical and other factors. 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 impairment charges. Adverse changes in our business or the overall operating environment, such as lower commodity prices, may affect our estimate of future operating results, which could result in future impairment due to the potential impact on our operations and cash flows.

A reduction in demand for NGL products by the petrochemical, refining or other industries or by the fuel markets could materially adversely affect our results of operations and financial condition.

The NGL products we produce have a variety of applications, including as heating fuels, petrochemical feedstocks and refining blend stocks. A reduction in demand for NGL products, whether because of general or industry specific economic conditions, new government regulations, global competition, reduced demand by consumers for products made with NGL products (for example, reduced petrochemical demand observed due to lower activity in the automobile and construction industries), increased competition from petroleum-based feedstocks due to pricing differences, mild winter weather for some NGL applications or other reasons, could result in a decline in the volume of NGL products we handle or reduce the fees we charge for our services.

Volumes of natural gas dedicated to our systems in the future may be less than we anticipate.

If the reserves connected to our gathering systems are less than we anticipate and we are unable to secure additional sources of natural gas, then the volumes of natural gas on our systems in the future could be less than we anticipate.

We depend on certain natural gas producer customers for a significant portion of our supply of natural gas and NGLs.

We identify as primary natural gas suppliers those suppliers individually representing 10% or more of our total natural gas and NGLs supply. We have no natural gas supplier representing 10% or more of our total natural gas and NGLs supply following the Transaction. While some of these customers are subject to long-term contracts, we may be unable to negotiate extensions or replacements of these contracts on favorable terms, if at all. The loss of all or even a portion of the natural gas and NGL volumes supplied by these customers, as a result of competition or otherwise, could have a material adverse effect on our business.

Because of the natural decline in production from existing wells, our success depends on our ability to obtain new sources of supplies of natural gas and NGLs.

Our gathering and transportation pipeline systems are connected to or dependent on the level of production from natural gas and crude wells, from which production will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. In order to maintain or increase throughput levels on our gathering and transportation pipeline systems and NGL pipelines and the asset utilization rates at our natural gas processing plants, we must continually obtain new supplies. The primary factors affecting our ability to obtain new supplies of natural gas and NGLs, and to attract new customers to our assets include the level of successful drilling activity near these assets, the demand for natural gas, crude oil and NGLs, producers' desire and ability to obtain necessary permits in an efficient manner, natural gas field characteristics and production performance, surface access and infrastructure issues, and our ability to compete for volumes from successful new wells. If we are not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells or because of competition, throughput on our pipelines and the utilization rates of our treating and processing facilities would decline, which could have a material adverse effect on our business, results of operations, financial position and cash flows, and our ability to make cash distributions.

Third party pipelines and other facilities interconnected to our natural gas and NGL pipelines and facilities may become unavailable to transport, process or produce natural gas and NGLs.

We depend upon third party pipelines and other facilities that provide delivery options to and from our pipelines and facilities for the benefit of our customers. Since we do not own or operate any of these third-party pipelines or other facilities, their continuing operation is not within our control and may become unavailable to transport, process or produce natural gas and NGLs.

We may not successfully balance our purchases and sales of natural gas and propane.

We purchase from producers and other customers a substantial amount of the natural gas that flows through our natural gas gathering, processing and transportation systems for resale to third parties, including natural gas marketers and end-users. In addition, in our wholesale propane logistics business, we purchase propane from a variety of sources and resell the propane to distributors. We may not be successful in balancing our purchases and sales. A producer or supplier could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a purchaser could purchase less than contracted volumes. Any of these actions could cause our purchases and sales to be unbalanced. While we attempt to balance our purchases and sales, if our purchases and sales are unbalanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income and cash flows.

Our ability to manage and grow our business effectively could be adversely affected if we or DCP Midstream, LLC and its subsidiaries fail to attract and retain key management personnel and skilled employees.

We rely on our executive management team to manage our day-to-day affairs and establish and execute our strategic business and operational plans. This executive management team has significant experience in the midstream energy industry. The loss of any of our executives or the failure to fill new positions created by expansion, turnover or retirement could adversely affect our ability to implement our business strategy. In addition, our operations require engineers, operational and field technicians and other highly skilled employees. Competition for experienced executives and skilled employees is intense and increases when the demand from other energy companies for such personnel is high. Our ability to execute on our business strategy and to grow or continue our level of service to our current customers may be impaired and our business may be adversely impacted if we or DCP Midstream, LLC and its subsidiaries are unable to attract, train and retain such personnel, which may have an adverse effect on our results of operations and ability to make cash distributions.

A downgrade of our credit rating could impact our liquidity, access to capital and our costs of doing business, and independent third parties determine our credit ratings outside of our control.

In January 2017, our credit rating was lowered and the cost of borrowing under our Amended and Restated Credit Agreement increased. The further lowering of our credit rating could further increase our cost of borrowing under our Amended and Restated Credit Agreement and could require us to post collateral with third parties, including our hedging arrangements, which could negatively impact our available liquidity and increase our cost of debt.

Credit rating agencies perform independent analysis when assigning credit ratings. The analysis includes a number of criteria including, but not limited to, business composition, market and operational risks, as well as various financial tests. Credit rating agencies continue to review the criteria for industry sectors and various debt ratings and may make changes to those criteria from time to time. Credit ratings are not recommendations to buy, sell or hold our securities, although such credit ratings may affect the market value of our debt instruments. Ratings are subject to revision or withdrawal at any time by the ratings agencies.

Our debt levels may limit our flexibility in obtaining additional financing and in pursuing other business opportunities.

We continue to have the ability to incur additional debt, subject to limitations within our Amended and Restated Credit Agreement. Our level of debt could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- an increased amount of cash flow will be required to make interest payments on our debt;
- our debt level will make us more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our debt level may limit our flexibility in responding to changing business and economic conditions.

Our ability to obtain new debt funding or service our existing debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors. In addition, our ability to service debt under our Amended and Restated Credit Agreement will depend on market interest rates. If our operating results are not sufficient to service our current or future indebtedness, we may take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing our debt, or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms, or at all.

Restrictions in our Amended and Restated Credit Agreement and the indentures governing our notes may limit our ability to make distributions to unitholders and may limit our ability to capitalize on acquisitions and other business opportunities.
Our Amended and Restated Credit Agreement and the indentures governing our notes contain covenants limiting our ability to make distributions, incur indebtedness, grant liens, make acquisitions, investments or dispositions and engage in transactions with affiliates. Furthermore, our Amended and Restated Credit Agreement contains covenants requiring us to maintain a certain leverage ratio and certain other tests. Any subsequent replacement of our Amended and Restated Credit Agreement or any new indebtedness could have similar or greater restrictions. If our covenants are not met, whether as a result of reduced production levels of natural gas and NGLs as described above or otherwise, our financial condition, results of operations and ability to make distributions to our unitholders could be materially adversely affected.

Changes in interest rates may adversely impact our ability to issue additional equity or incur debt, as well as the ability of exploration and production companies to finance new drilling programs around our systems.

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase. As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could impair our ability to issue additional equity or incur debt to make acquisitions, for other purposes. Increased interest costs could also inhibit the financing of new capital drilling programs by exploration and production companies served by our systems.

The outstanding senior notes and junior subordinated notes, or notes, are unsecured obligations of our operating subsidiary, DCP Midstream Operating, LP, or DCP Operating, and are not guaranteed by any of our subsidiaries. As a result, our notes are effectively junior to DCP Operating’s existing and future secured debt and to all debt and other liabilities of its subsidiaries.

The 2.50% Senior Notes due 2017, 2.70% Senior Notes due 2019, 9.75% Senior Notes due 2019, 5.35% Senior Notes due 2020, 4.75% Senior Notes due 2021, 4.95% Senior Notes due 2022, 3.875% Senior Notes due 2023, 8.125% Senior Notes due 2030, 6.450% Senior Notes due 2036, 6.750% Senior Notes due 2037, and 5.60% Senior Notes due 2044, or the Senior Notes, are senior unsecured obligations DCP Operating and rank equally in right of payment with all of its other existing and future senior unsecured debt and effectively junior to any of its future secured indebtedness to the extent of the collateral securing such indebtedness. The 5.85% Fixed-to-Floating Rate Junior Subordinated Notes due 2043 are junior subordinated obligations of DCP Operating and rank junior in right of payment with all of its other existing and future senior unsecured debt. All of our operating assets are owned by our subsidiaries, and none of these subsidiaries guarantee DCP Operating’s obligations with respect to the notes. Creditors of DCP Operating’s subsidiaries may have claims with respect to the assets of those subsidiaries that rank effectively senior to the notes. In the event of any distribution or payment of assets of such subsidiaries in any dissolution, winding up, liquidation, reorganization or bankruptcy proceeding, the claims of those creditors would be satisfied prior to making any such distribution or payment to DCP Operating in respect of its direct or indirect equity interests in such subsidiaries.

Consequently, after satisfaction of the claims of such creditors, there may be little or no amounts left available to make payments in respect of our notes. As of December 31, 2016, DCP Operating’s subsidiaries had no debt for borrowed money owing to any unaffiliated third parties. However, such subsidiaries are not prohibited under the indentures governing the notes from incurring indebtedness in the future.

In addition, because our notes and our guarantees of our notes are unsecured, holders of any secured indebtedness of us would have claims with respect to the assets constituting collateral for such indebtedness that are senior to the claims of the holders of our notes. Currently, we do not have any secured indebtedness. Although the indentures governing our notes places some limitations on our ability to create liens securing debt, there are significant exceptions to these limitations that will allow us to secure significant amounts of indebtedness without equally and ratably securing the notes. If we incur secured indebtedness and such indebtedness is either accelerated or becomes subject to a bankruptcy, liquidation or reorganization, our assets would be used to satisfy obligations with respect to the indebtedness secured thereby before any payment could be made on our notes. Consequently, any such secured indebtedness would effectively be senior to our notes and our guarantee of our notes, to the extent of the value of the collateral securing the secured indebtedness. In that event, our noteholders may not be able to recover all the principal or interest due under our notes.

Our significant indebtedness and the restrictions in our debt agreements may adversely affect our future financial and operating flexibility.

As of December 31, 2016, our consolidated principal indebtedness was $2,270 million and, as of February 3, 2017, after giving effect to the Transaction, our consolidated principal indebtedness was $5,225 million. Our significant indebtedness and the additional debt we may incur in the future for potential acquisitions may adversely affect our liquidity and therefore our ability to make interest payments on our notes.

Debt service obligations and restrictive covenants in our Amended and Restated Credit Agreement, and the indentures governing our notes may adversely affect our ability to finance future operations, pursue acquisitions and fund other capital needs as well as our ability to make cash distributions to our unitholders. In addition, this leverage may make our results of operations more susceptible to adverse economic or operating conditions by limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate and may place us at a competitive disadvantage as compared to our competitors that have less debt.

If we incur any additional indebtedness, including trade payables, that ranks equally with our notes, the holders of that debt will be entitled to share ratably with the holders of our notes in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding up of us or DCP Operating. This may have the effect of reducing the amount of proceeds paid to our noteholders. If new debt is added to our current debt levels, the related risks that we now face could intensify.

The adoption of financial reform legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to hedge risks associated with our business.

We hedge a portion of our commodity risk and our interest rate risk. In its rulemaking under the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Act, the Commodities Futures Trading Commission, or CFTC, adopted regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents, but these rules were successfully challenged in Federal district court by the Securities Industry Financial Markets Association and the International Swaps and Derivatives Association and largely vacated by the court. In December 2016, the CFTC reproposed rules that place limits on speculative positions in certain physical commodity futures and options contracts and their "economically equivalent" swaps, including NYMEX Henry Hub Natural Gas and NYMEX Light Sweet Crude Oil contracts, subject to exceptions for certain bona fide hedging transactions. The comment period for these new rules closes on February 28, 2017. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time. Under the reproposed rules, we believe our hedging transactions will qualify for the non-financial, commercial end user exception, which exempts derivatives intended to hedge or mitigate commercial risk from the mandatory swap clearing requirement, and as a result, we do not expect our hedging activity to be subject to mandatory clearing. The Act may also require us to comply with margin requirements in connection with our hedging activities, although the application of those provisions to us is uncertain at this time. The Act may also require the counterparties to our derivative instruments to spin off some of their hedging activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and related regulations could significantly increase the cost of derivatives contracts for our industry (including requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivatives contracts, and increase our exposure to less creditworthy counterparties, particularly if we are unable to utilize the commercial end user exception with respect to certain of our hedging transactions. If we reduce our use of hedging as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and fund unitholder distributions. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our business, our financial condition, and our results of operations.

Future disruptions in the global credit markets may make equity and debt markets less accessible and capital markets more costly, create a shortage in the availability of credit and lead to credit market volatility, which could disrupt our financing plans and limit our ability to grow.

From time to time, public equity markets experience significant declines, and global credit markets experience a shortage in overall liquidity and a resulting disruption in the availability of credit. Future disruptions in the global financial marketplace, including the bankruptcy or restructuring of financial institutions, could make equity and debt markets inaccessible, and adversely affect the availability of credit already arranged and the availability and cost of credit in the future. We have availability under our Amended and Restated Credit Agreement to borrow additional capital, but our ability to borrow under that facility could be impaired if one or more of our lenders fails to honor its contractual obligation to lend to us.

As a publicly traded partnership, these developments could significantly impair our ability to make acquisitions or finance growth projects. We distribute all of our available cash, as defined in our partnership agreement, to our unitholders on a quarterly basis. We rely upon external financing sources, including the issuance of debt and equity securities and bank borrowings, to fund acquisitions or expansion capital expenditures or fund routine periodic working capital needs. Any limitations on our access to external capital, including limitations caused by illiquidity or volatility in the capital markets, may impair our ability to complete future acquisitions and construction projects on favorable terms, if at all. As a result, we may be at a competitive disadvantage as compared to businesses that reinvest all of their available cash to expand ongoing operations, particularly under adverse economic conditions.

Volatility in the capital markets may adversely impact our liquidity.

The capital markets may experience volatility, which may lead to financial uncertainty. Our access to funds under the Amended and Restated Credit Agreement is dependent on the ability of the lenders that are party to the Amended and Restated Credit Agreement to meet their funding obligations. Those lenders may not be able to meet their funding commitments if they experience shortages of capital and liquidity. If lenders under the Amended and Restated Credit Agreement were to fail to fund their share of the Amended and Restated Credit Agreement, our available borrowings could be further reduced. In addition, our borrowing capacity may be further limited by the Amended and Restated Credit Agreement’s financial covenants.

A significant downturn in the economy could adversely affect our results of operations, financial position or cash flows. In the event that our results were negatively impacted, we could require additional borrowings. A deterioration of the capital markets could adversely affect our ability to access funds on reasonable terms in a timely manner.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets.

The partnership is a holding company, and our subsidiaries conduct all of our operations and own all of our operating assets. We do not have significant assets other than equity in our subsidiaries and equity investees. As a result, our ability to make required payments on our notes depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, credit instruments, applicable state business organization laws and other laws and regulations. If our subsidiaries are prevented from distributing funds to us, we may be unable to pay all the principal and interest on the notes when due.

We may incur significant costs and liabilities resulting from implementing and administering pipeline and asset integrity programs and related repairs.

Pursuant to the Pipeline Safety Improvement Act of 2002, PHMSA has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines located where a leak or rupture could do the most harm in “high consequence areas.” The regulations require operators to:

- perform ongoing assessments of pipeline integrity;
- identify threats to pipeline segments that could impact a high consequence area and assess the risks that such threats pose to pipeline integrity;
- collect, integrate, and analyze data regarding threats and risks posed to the pipeline;
- repair and remediate the pipeline as necessary; and

• implement preventive and mitigating actions.

Pipeline safety legislation enacted in 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, or the Pipeline Safety and Job Creations Act, reauthorizes funding for federal pipeline safety programs through 2015, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines, including the expansion of integrity management, use of automatic and remote-controlled shut-off valves, leak detection systems, sufficiency of existing regulation of gathering pipelines, use of excess flow valves, verification of maximum allowable operating pressure, incident notification, and other pipeline-safety related requirements. New rules proposed by PHMSA, address many areas of this legislation. Extending the integrity management requirements to our gathering lines would impose additional obligations on us and could add material cost to our operations.

Although many of our natural gas facilities currently are not subject to pipeline integrity requirements, we may incur significant costs and liabilities associated with repair, remediation, preventative or mitigation measures associated with non-exempt pipelines. Such costs and liabilities might relate to repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, or new requirements that may be imposed as a result of the Pipeline Safety and Job Creation Act, as well as lost cash flows resulting from shutting down our pipelines during the pendency of such repairs. Additionally, we may be affected by the testing, maintenance and repair of pipeline facilities downstream from our own facilities. With the exception of our Wattenberg pipeline, our NGL pipelines are also subject to integrity management and other safety regulations imposed by the Texas Railroad Commission, or TRRC.

We currently estimate that we will incur between $16 million and $20 million between 2017 and 2021 to implement pipeline integrity management program testing along certain segments of our natural gas and NGL pipelines. This does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, or new requirements that may be imposed as a result of the Pipeline Safety and Job Creation Act, which costs could be substantial.

We currently transport NGLs produced at our processing plants on our owned and third party NGL pipelines. Accordingly, in the event that an owned or third party NGL pipeline becomes inoperable due to any necessary repairs resulting from integrity testing programs or for any other reason for any significant period of time, we would need to transport NGLs by other means. There can be no assurance that we will be able to enter into alternative transportation arrangements under comparable terms.

Any new or expanded pipeline integrity requirements or the adoption of other asset integrity requirements could also increase our cost of operation and impair our ability to provide service during the period in which assessments and repairs take place, adversely affecting our business. Further, execution of and compliance with such integrity programs may cause us to incur greater than expected capital and operating expenditures for repairs and upgrades that are necessary to ensure the continued safe and reliable operation of our assets.

State and local legislative and regulatory initiatives relating to oil and gas operations could adversely affect our third-party customers’ production and, therefore, adversely impact our midstream operations.

Certain states in which we operate have adopted or are considering adopting measures that could impose new or more stringent requirements on oil and gas exploration and production activities. For example, the Colorado Oil and Gas Conservation Commission has adopted regulations to provide a mechanism for greater local government involvement in the siting and permitting of oil and gas production facilities, despite local government activists’ derision of the regulations as doing nothing to alleviate their concerns regarding the encroachment of oil and gas operations on urban areas. Although the Colorado Supreme Court recently struck down local government prohibitions on hydraulic fracturing as being preempted by state law and unenforceable, local governments may continue to pass ordinances and private individuals may continue to sponsor citizen initiatives to limit hydraulic fracturing, increase mandatory setbacks of oil and gas operations from occupied structures, and achieve more restrictive state or local control over such activities.

In the event state or local restrictions or prohibitions are adopted in our areas of operations, such as in the Wattenberg field, our customers may incur significant compliance costs or may experience delays or curtailment in the pursuit of their exploration, development, or production activities, and possibly be limited or precluded in the drilling of certain wells altogether. Any adverse impact on our customers' activities would have a corresponding negative impact on our throughput volumes. In addition, while conflicts associated with upstream development activities are the primary focus of debate in Colorado generally, certain proposals may, if adopted, directly impact our ability to competitively locate, construct, maintain, and operate our own assets.

Other jurisdictions are also considering policy measures that could have a direct impact on our ability to operate. In Oklahoma, legislation may be reintroduced in 2017 to extend the authority of the Oklahoma Corporation Commission to consider setting rates and terms and conditions of service for natural gas processing activities, and in Texas, independent producers have threatened to pursue legislation to authorize similar regulatory oversight by the Texas Railroad Commission. Also in Texas, surface owners are promoting the reintroduction of legislation introduced but not acted upon in 2015, which would award attorney’s fees and costs to landowners who receive final compensation pursuant to a condemnation proceeding that exceeds 120% of the final offer made by a condemnor. Accordingly, such restrictions or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, cash flows and ability to make distributions to our unitholders.

We may incur significant costs and liabilities in the future resulting from a failure to comply with existing or new environmental regulations or an accidental release of hazardous substances or hydrocarbons into the environment.

Our operations are subject to stringent and complex federal, state and local environmental laws and regulations. These include, for example, (1) the federal Clean Air Act and comparable state laws and regulations, including federal and state air permits, that impose obligations related to air emissions; (2) the federal Resource Conservation and Recovery Act, as amended, or RCRA, and comparable state laws that impose requirements for the management, storage and disposal of solid and hazardous waste from our facilities; (3) the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, or CERCLA, also known as “Superfund,” and comparable state laws that 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 waste for disposal; (4) the Clean Water Act and the Oil Pollution Act, and comparable state laws that impose requirements on discharges to waters as well as requirements to prevent and respond to releases of hydrocarbons to Waters of the United States and regulated state waters; and (5) state laws that impose requirements on the response to and remediation of hydrocarbon releases to soil and managing related wastes. Failure to comply with these laws and regulations or newly adopted laws or regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining or affecting future operations. Certain environmental regulations, including CERCLA and analogous state laws and regulations, impose strict liability and joint and several liability for costs required to clean up and restore sites where hazardous substances, and in some cases hydrocarbons, have been disposed or otherwise released.

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to our handling of natural gas, NGLs and other petroleum products, air emissions related to our operations, and historical industry operations and waste management and disposal practices. For example, an accidental release from one of our facilities could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage, governmental claims for natural resource damages or imposing fines or penalties for related violations of environmental laws, permits or regulations. In addition, it is possible 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 not be able to recover some or any of these costs from insurance or third-party indemnification.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets.

The majority of our natural gas gathering and intrastate transportation operations are exempt from FERC regulation under the NGA but FERC regulation still affects these businesses and the markets for products derived from these businesses. FERC’s policies and practices across the range of its oil and natural gas regulatory activities, including, for example, its policies on open access transportation, ratemaking, capacity release and market center promotion, indirectly affect intrastate markets. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate oil and natural gas pipelines. However, we cannot assure that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to oil and natural gas transportation capacity. In addition, the distinction between FERC-regulated transportation services and federally unregulated gathering services has been the subject of regular litigation, so the classification and regulation of some of our gathering facilities and intrastate transportation pipelines may be subject to change based on any reassessment by us of the jurisdictional status of our facilities or on future determinations by FERC and the courts.

In addition, the rates, terms and conditions of some of the transportation services we provide on certain of our pipeline systems are subject to FERC regulation under Section 311 of the NGPA. Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest.

Several of our pipelines are interstate transporters of NGLs and are subject to FERC jurisdiction under the Interstate Commerce Act and the Elkins Act. The base interstate tariff rates for our NGL pipelines are determined either by a FERC cost-of-service proceeding or by agreement with an unaffiliated party, and adjusted annually through the FERC's indexing methodology. The NGL pipelines may also provide incentive rates, which offer tariff rates below the base tariff rates for high volume shipments.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under EPACT 2005, FERC has civil penalty authority under the NGA to impose penalties of up to $1 million per day for each violation and possible criminal penalties of up to $1 million per violation and five years in prison. Under the NGPA, FERC may impose civil penalties of up to $1 million for any one violation and may impose criminal penalties of up to $1 million and five years in prison.

Other state and local regulations also affect our business. Our non-proprietary gathering lines are subject to ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, oil or natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes restrict our right as an owner of gathering facilities to decide with whom we contract to purchase or transport oil or natural gas. Federal law leaves any economic regulation of natural gas gathering to the states. The states in which we operate have adopted complaint-based regulation of oil and natural gas gathering activities, which allows oil and natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to oil and natural gas gathering access and rate discrimination. Other state regulations may not directly regulate our business, but may nonetheless affect the availability of natural gas for purchase, processing and sale, including state regulation of production rates and maximum daily production allowable from gas wells. While our proprietary gathering lines are currently subject to limited state regulation, there is a risk that state laws will be changed, which may give producers a stronger basis to challenge the proprietary status of a line, or the rates, terms and conditions of a gathering line providing transportation service.

The interstate tariff rates of certain of our pipelines are subject to review and possible adjustment by federal regulators.

FERC, pursuant to the NGA, regulates many aspects of our interstate natural gas pipeline transportation service, including the rates our pipelines are permitted to charge for such service. Under the NGA, interstate transportation rates must be just and reasonable and not unduly discriminatory. If FERC fails to permit our requested tariff rate increases, or if FERC lowers the tariff rates we are permitted to charge, on its own initiative, or as a result of challenges raised by customers or third parties, our tariff rates may be insufficient to recover the full cost of providing interstate transportation service. In certain circumstances, FERC also has the power to order refunds.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and the disgorgement of profits. Under EPACT 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and possible criminal penalties of up to $1 million per violation and five years in prison.

The transportation rates for our NGL pipelines that provide interstate transportation services, our interstate natural gas pipelines, and our intrastate pipelines that provide interstate services under Section 311 of the NGPA could be adversely impacted by potential changes to FERC's income tax allowance policy for partnership pipelines.

Under current policy, FERC permits pipelines to include, in the cost-of-service used as the basis for calculating the pipeline's regulated rates, a tax allowance reflecting the actual or potential income tax liability on public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Under current policy, whether a pipeline's owners have such actual or potential income tax liability is reviewed by FERC on a case-by-case basis, and our pipelines' ability to recover an income tax allowance in a cost-of-service proceeding before FERC is subject to this review and potentially impacted by ultimate partnership ownership. On December 15, 2016, FERC issued a Notice of Inquiry (NOI) regarding its income tax recovery policy following a decision by the U.S. Court of Appeals for the D.C. Circuit, issued in July 2016, that found FERC did not demonstrate there is no double recovery of income taxes for a partnership owned pipeline as a result of the income tax allowance and return on equity policies in a cost-of-service proceeding for an oil pipeline. While the Court of Appeals remand to FERC focused on a specific case, FERC's issuance of an NOI seeks comments on how to address any double-recovery of income taxes and also broader industry comments related to the impact on all regulated industries, including natural gas pipelines, oil pipelines and electric utilities. We cannot predict the outcome of this proceeding, but any shift in policy could impact future rate proceedings for our pipelines organized as partnerships and could adversely affect our revenues for our rates calculated using a cost-of-service methodology.

Spills and their aftermath could lead to additional governmental regulation of the offshore exploration and production industry, which may result in substantial cost increases or delays in our offshore natural gas gathering activities.

In April 2010, a deepwater exploration well located in the Gulf of Mexico, owned and operated by companies unrelated to us, sustained a blowout and subsequent explosion leading to the leaking of hydrocarbons. In response to this event, certain federal agencies and governmental officials ordered additional inspections of deepwater operations in the Gulf of Mexico. On May 28, 2010, a six-month federal moratorium was implemented on all offshore deepwater drilling projects. On October 12, 2010, the Department of the Interior announced it was lifting the deepwater drilling moratorium. Despite the fact that the drilling moratorium was lifted, this spill and its aftermath has led to additional governmental regulation of the offshore exploration and production industry, such as the Bureau of Ocean Energy Management's July 2016 imposition of more rigorous financial assurance and risk management requirements relating to decommissioning liabilities for outer continental shelf lessees, and delays in the issuance of drilling permits, which may result in volume impacts, cost increases or delays in our offshore natural gas gathering activities, which could materially impact Discovery’s operations, including Keathley Canyon, and our business, financial condition and results of operations.

Recently proposed or finalized rules imposing more stringent requirements on the oil and gas industry could cause our customers and us to incur increased capital expenditures and operating costs as well as reduce the demand for our services.

On August 16, 2012, the EPA issued final regulations under the Clean Air Act that, among other things, require additional emissions controls for natural gas and natural gas liquids production, including New Source Performance Standards, or NSPS, to address emissions of sulfur dioxide and volatile organic compounds, or VOCs, and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require, among other things, the reduction of VOC emissions from existing natural gas wells that are re-fractured, as well as newly-drilled and fractured wells through the use of reduced emission completions or “green completions” and well completion combustion devices, such as flaring, as of January 1, 2015. In addition, these rules establish specific requirements regarding emissions from compressors and controllers at natural gas gathering and boosting stations and processing plants together with emissions reduction requirements for dehydrators and storage tanks at natural gas processing plants, compressor stations and gathering and boosting stations. The rules further establish new requirements for detection and repair of VOC leaks exceeding 500 parts per million in concentration at new or modified natural gas processing plants. The EPA made certain revisions to the regulation from 2013 to 2015, and the regulation is also the subject of Petitions for Review before the U.S. Circuit Court of Appeals for the District of Columbia. In addition, in January 2015, the EPA announced its intention to expand existing NSPS regulations for new or modified sources of VOCs and to include methane emissions, and institute Control Techniques Guidelines for VOC emissions reductions related to ozone non-attainment areas, as part of the EPA’s strategy to reduce methane and ozone-forming VOC emissions from the oil and gas industry. These regulations and guidelines were finalized by EPA in June and October 2016, respectively, and are intended to be instituted by the EPA over the course of 2016 to 2019. Among other things, these regulations impose leak detection and repair requirements for VOCs and methane on producer well site equipment and on midstream equipment such as compressor and booster stations, impose additional emission reduction requirements on specific pieces of oil and gas equipment, and they are a regulatory pre-condition to EPA acting to regulate existing oil and gas methane sources in the future under Section 111(d) of the Clean Air Act. This regulation is the subject of a Petition for Review before the U.S. Circuit Court of Appeals for the District of Columbia. In a related action, in November 2016, EPA issued oil and natural gas companies a final information request as part of an effort to develop standards under the Clean Air Act NSPS provisions for methane and other emissions from existing sources in the oil and natural gas industry. The request requires companies to provide EPA with a wide range of information related to operations, equipment, and emissions controls within 180 days of receipt. It is unclear whether the incoming Trump Administration will proceed with developing an existing source rule based on the information collected through this request. Relatedly, in October 2015, the EPA revised and lowered the ambient air quality standard for ozone in the U.S. under the Clean Air Act, from 75 parts per billion to 70 parts per billion, which is likely to result in more, and expanded, ozone non-attainment areas, which in turn will require states to adopt implementation plans to reduce emissions of ozone-forming pollutants, like VOCs and nitrogen oxides, that are emitted from, among others, the oil and gas industry. Persistent non-attainment status, for example for ozone, can result in lower major source permitting thresholds, making it more costly and complex to site and permit major new or modified facilities. In October 2016, the EPA finalized Control Techniques Guidelines for VOC emissions from existing oil and natural gas equipment and processes in moderate ozone non-attainment areas. These Control Technique Guidelines provide recommendations for states and local air agencies to consider when determining what emissions requirements apply to sources in the non-attainment areas. These regulations could require modifications to the operations of our natural gas exploration and production customers, as well as our operations, including the installation of new equipment and new emissions management practices, which could result in significant additional costs, both increased capital expenditures and operating costs. The incurrence of such expenditures and costs by our customers could also result in reduced production by those customers and thus translate into reduced demand for our services, which could in turn have an adverse effect on our business and cash available for distributions.

We may incur significant costs in the future associated with proposed climate change regulation and legislation.

The United States Congress and some states where we have operations may consider legislation related to greenhouse gas emissions, including methane emissions, which may compel reductions of such emissions. In addition, there have recently been international conventions and efforts to establish standards for the reduction of greenhouse gases globally, including the Paris accords in December 2015. The conditions for entry into force of the Paris accords were met on October 5, 2016 and the Agreement went into force 30 days later on November 4, 2016. Some of these proposals have included or could include limitations, or caps, on the amount of greenhouse gas that can be emitted, as well as a system of emissions allowances. Legislation passed by the U.S. House of Representatives in 2010, which was not taken up by the Senate, would have placed the entire burden of obtaining allowances for the carbon content of NGLs on the owners of NGLs at the point of fractionation. In June 2013, the President announced a climate action plan that targets methane emissions from the oil and gas industry as part of a comprehensive interagency methane reduction strategy, and in June 2016, the EPA finalized new source performance standards for methane emissions (a greenhouse gas) from new and modified oil and gas industry sources. The EPA also finalized in October 2016 Control Techniques Guidelines for emissions of VOCs from oil and gas industry sources in ozone nonattainment areas, with an expected co-benefit of reduced methane emissions, and, relatedly, in October 2015, the EPA finalized a regulation reducing the ambient ozone standard from 75 parts per billion to 70 parts per billion under the Clean Air Act. The EPA in 2011 issued permitting rules for sources of greenhouse gases; however, in June 2014, the U.S. Supreme Court reversed a D.C. Circuit Court of Appeals decision upholding these rules and struck down the EPA’s greenhouse gas permitting rules to the extent they impose a requirement to obtain a permit based solely on emissions of greenhouse gases. Under the Court ruling and the EPA's subsequent proposed rules, major sources of other air pollutants, such as VOCs or nitrogen oxides, could still be required to implement process or technology controls and obtain permits regarding emissions of greenhouse gases. Further, the EPA also has issued rules requiring reporting of greenhouse gas, on an annual basis, for certain onshore natural gas and oil production facilities, and in October 2015, the EPA amended and expanded those greenhouse gas reporting requirements to all segments of the oil and gas industry effective January 1, 2016. To the extent legislation is enacted or additional regulations are promulgated that regulate greenhouse gas emissions, it could significantly increase our costs to (i) acquire allowances; (ii) permit new large facilities; (iii) operate and maintain our facilities; (iv) install new emission controls or institute emission reduction measures; and (v) manage a greenhouse gas emissions program. If such legislation becomes law or additional rules are promulgated in the United States or any states in which we have operations and we are unable to pass these costs through as part of our services, it could have an adverse effect on our business and cash available for distributions.

Increased regulation of hydraulic fracturing could result in reductions, delays or increased costs in drilling and completing new oil and natural gas wells, which could adversely impact our revenues by decreasing the volumes of natural gas that we gather, process and transport.

Certain of our customers' natural gas is developed from formations requiring hydraulic fracturing as part of the completion process. Fracturing is a process where water, sand, and chemicals are injected under pressure into subsurface formations to stimulate hydrocarbon production. While the underground injection of fluids is regulated by the EPA under the Safe Drinking Water Act, or SDWA, fracturing is excluded from regulation unless the injection fluid is diesel fuel. The EPA has published an interpretive memorandum and permitting guidance related to regulation of fracturing fluids using this regulatory authority. The EPA has finalized various regulatory programs directed at hydraulic fracturing. For example, in June 2016, the EPA issued regulations under the federal Clean Water Act to further regulate wastewater discharges from hydraulic fracturing and other natural gas production to publicly-owned treatment works. The EPA also expanded, as discussed herein, existing Clean Air Act new source performance standards for new and modified air emissions sources, and finalized Control Techniques Guidelines for existing sources in ozone non-attainment areas, to reduce emissions of methane or VOCs from oil and gas sources, including drilling and production processes. The adoption of new federal laws or regulations imposing reporting obligations on, or otherwise limiting or regulating, the hydraulic fracturing process could make it more difficult for our customers to complete oil and natural gas wells in shale formations and increase their costs of compliance. In addition, the EPA has studied the potential adverse impact that each stage of hydraulic fracturing may have on the environment; the EPA released a final assessment report of the potential impacts of hydraulic fracturing on drinking water resources in December 2016. Several states in which our customers operate have also adopted regulations requiring disclosure of fracturing fluid components or otherwise regulate their use more closely. In Oklahoma, induced seismicity from injection of fluids in wastewater disposal wells has resulted in regulatory limitations on wastewater disposal into such wells. Under a recent settlement agreement, the EPA will decide by March 2019 whether to initiate rulemaking governing the disposal of wastewater from oil and natural gas development.

In addition, federal agencies have recently initiated certain other regulatory initiatives or reviews of certain aspects of hydraulic fracturing that could further increase our natural gas exploration and production customer's costs and decrease their levels of production. On March 26, 2015, the federal Bureau of Land Management, or BLM, finalized regulations requiring disclosure of chemicals used in hydraulic fracturing activities upon Native American Indian and other federal lands, and added requirements on the use of hydraulic fracturing techniques and management of produced water on these lands, which regulation was overturned by the U.S. District Court of Wyoming on June 21, 2016. On November 18, 2016, the BLM finalized regulations to, among other things, curtail the flaring during the production of natural gas and oil on Native American Indian and other federal lands, which affects how hydraulically fractured wells are developed and operated. The U.S. District Court denied a preliminary injunction sought by industry groups and the regulation went into effect on January 17, 2017; however, legal challenge to the rule continues, and the U.S. House of Representatives is considering legislation to invalidate the regulation. The implementation of rules relating to hydraulic fracturing could result in increased expenditures for our natural gas exploration and production customers, which could cause them to reduce their production and thereby result in reduced demand for our services by these customers.

Construction of new assets is subject to regulatory, environmental, political, legal, economic, civil protest, and other risks that may adversely affect our financial results.

The construction of new midstream facilities or additions or modifications to our existing midstream asset systems or propane terminals involves numerous regulatory, environmental, political and legal and economic uncertainties beyond our control and may require the expenditure of significant amounts of capital. For example, civil protests regarding environmental and social issues, including construction of infrastructure associated with fossil fuels, may lead to increased legislative and regulatory initiatives and review at federal, state, and local levels of government that could prevent or delay the construction of such infrastructure and realization of associated revenues. Construction expenditures may occur over an extended period of time, yet we will not receive any material increases in cash flow until the project is completed and fully operational. Moreover, our cash flow from a project may be delayed or may not meet our expectations. These projects may not be completed on schedule or within budgeted cost, or at all. We may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. Since we are not engaged in the exploration for and development of natural gas and oil reserves, we often do not have access to third party estimates of potential reserves in an area prior to constructing facilities in such area. To the extent we rely on estimates of future production in our decision to construct new systems or additions to our systems, such estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of future production. As a result, these facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition. The construction of new systems or additions to our existing gathering, transportation and propane terminal assets may require us to obtain new rights-of-way prior to constructing these facilities. We may be unable to obtain such rights-of-way to connect new natural gas supplies to our existing gathering lines, expand our network of propane terminals, or capitalize on other attractive expansion opportunities. The construction of new systems or additions to our existing gathering, transportation and propane terminal assets may require us to rely on third parties downstream of our facilities to have available capacity for our delivered natural gas, NGLs, or propane. If such third party facilities are not constructed or operational at the time that the addition to our facilities is completed, we may experience adverse effects on our results of operations and financial condition. The construction of additional systems may require greater capital investment if the commodity prices of certain supplies such as steel increase. Construction also subjects us to risks related to the ability to construct projects within anticipated costs, including the risk of cost overruns resulting from inflation or increased costs of equipment, materials, labor, or other factors beyond our control that could adversely affect results of operations, financial position or cash flows.

We are exposed to the credit risks of our key producer customers and propane purchasers, and any material nonpayment or nonperformance by our key producer customers or our propane purchasers could reduce our ability to make distributions to our unitholders.

We are subject to risks of loss resulting from nonpayment or nonperformance by our producer customers and propane purchasers. Any material nonpayment or nonperformance by our key producer customers or our propane purchasers could reduce our ability to make distributions to our unitholders. Furthermore, some of our producer customers or our propane purchasers may be highly leveraged and subject to their own operating and regulatory risks, which could increase the risk that they may default on their obligations to us. Additionally, a decline in the availability of credit to producers in and surrounding our geographic footprint could decrease the level of capital investment and growth that would otherwise bring new volumes to our existing assets and facilities.

If we do not make acquisitions on economically acceptable terms, our future growth could be limited.

Our ability to make acquisitions that are accretive to our cash generated from operations per unit is based upon our ability to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them and obtain financing for these acquisitions on economically acceptable terms. 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 per unit. Additionally, net assets contributed by DCP Midstream, LLC represent a transfer of net assets between entities under common control, and are recognized at DCP Midstream, LLC's basis in the net assets transferred. The amount of the purchase price in excess of DCP Midstream, LLC's basis in the net assets, if any, is recognized as a reduction to partners' equity. Conversely, the amount of the purchase price less than DCP Midstream's basis in the net assets, if any, is recognized as an increase to partners' equity.

Any acquisition involves potential risks, including, among other things:
- mistaken assumptions about volumes, future contract terms with customers, revenues and costs, including synergies;
- an inability to successfully integrate the businesses we acquire;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business concerns;
- change in competitive landscape;
- unforeseen difficulties operating in new product areas or new geographic areas; and
- customer or key employee losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

In addition, any limitations on our access to substantial new capital to finance strategic acquisitions will impair our ability to execute this component of our growth strategy. If the cost of such capital becomes too expensive, our ability to develop or acquire accretive assets will be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence our cost of capital include market conditions and offering or borrowing costs such as interest rates or underwriting discounts.

We may not be able to grow or effectively manage our growth.

Historically, a principal focus of our strategy was to continue to grow the per unit distribution on our units by expanding our business. However, with the downturn in the energy industry caused by the volatility in the commodity prices we are currently focusing on sustaining the per unit distribution on our units. The Transaction resulted in significant growth of the partnership, but also in the loss of certain future drop-down opportunities from DCP Midstream, LLC. Our future growth will depend upon a number of factors, some of which we can control and some of which we cannot. These factors include our ability to:
- complete construction projects and consummate accretive acquisitions or joint ventures;
- identify businesses engaged in managing, operating or owning pipelines, processing and storage assets or other midstream assets for acquisitions, joint ventures and construction projects;
- appropriately identify liabilities associated with acquired businesses or assets;
- integrate acquired or constructed businesses or assets successfully with our existing operations and into our operating and financial systems and controls;
- hire, train and retain qualified personnel to manage and operate our growing business; and
- obtain required financing for our existing and new operations at reasonable rates.

A deficiency in any of these factors could adversely affect our ability to sustain the level of our cash flows or realize benefits from acquisitions, joint ventures or construction projects. In addition, competition from other buyers could reduce our acquisition opportunities. DCP Midstream, LLC and its affiliates are not restricted from competing with us. DCP Midstream, LLC and its affiliates may acquire, construct or dispose of midstream or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets. Furthermore, in recent years we have grown through organic projects, dropdowns and acquisitions. If we fail to properly integrate these assets successfully with our existing operations, if the future performance of these assets does not meet our expectations, if we did not properly value the assets, or we did not identify significant liabilities associated with acquired assets, the anticipated benefits from these transactions may not be fully realized.

Dropdowns and acquisitions, including the Transaction, may not be beneficial to us.
Dropdowns and acquisitions involve numerous risks, including:

- the failure to realize expected profitability, growth or accretion;
- an increase in indebtedness and borrowing costs;
- potential environmental or regulatory compliance matters or liabilities;
- potential title issues;
- the incurrence of unanticipated liabilities and costs; and
- the temporary diversion of management’s attention from managing the remainder of our assets to the process of integrating the acquired businesses.

Assets recently acquired will also be subject to many of the same risks as our existing assets. If any of these risks or unanticipated liabilities or costs were to materialize, any desired benefits of these acquisitions may not be fully realized, if at all, and our future financial performance and results of operations could be negatively impacted.

If we are not able to purchase propane from our principal suppliers, or we are unable to secure transportation under our transportation arrangements, our results of operations in our wholesale propane logistics business would be adversely affected.

Most of our propane purchases are made under supply contracts that are annual or multi-year agreements and provide various index-based pricing formulas. We identify primary suppliers as those individually representing 10% or more of our total propane supply. Our two primary suppliers of propane, one of which is an affiliated entity, represented approximately 95% of our propane supplied during the year ended December 31, 2016. In the event that we are unable to purchase propane from our significant suppliers due to their failure to perform under contractual obligations or otherwise, replace terminated or expired supply contracts, or if there are domestic or international supply disruptions, our failure to obtain alternate sources of supply at competitive prices and on a timely basis would affect our ability to satisfy customer demand, reduce our revenues and adversely affect our results of operations. In addition, if we are unable to transport propane supply to our terminals, our ability to satisfy customer demand, our revenue and results of operations would be adversely affected.

Service at our propane terminals may be interrupted.

Historically, a substantial portion of the propane we purchase to support our wholesale propane logistics business is delivered at our rail terminals or our owned marine terminal in Chesapeake, Virginia. We also rely on shipments of propane via TEPPCO Partners, LP’s pipeline to open access terminals. Any significant interruption in the service at these terminals would adversely affect our ability to obtain propane, which could reduce the amount of propane that we distribute and impact our revenues or cash available for distribution.

Our operating results for our Wholesale Propane Logistics Segment fluctuate on a seasonal and quarterly basis.

Revenues from our Wholesale Propane Logistics Segment have seasonal characteristics. In many parts of the country, demand for propane and other fuels peaks during the winter months. As a result, our overall operating results fluctuate on a seasonal basis. Demand for propane and other fuels could vary significantly from our expectations depending on the nature and location of our facilities and pipeline systems and the terms of our transportation arrangements relative to demand created by unusual weather patterns.

Our assets and operations can be affected by weather, weather-related conditions and other natural phenomena.

Our assets and operations can be adversely affected by hurricanes, floods, tornadoes, wind, lightning, cold weather and other natural phenomena, which could impact our results of operations and make it more difficult for us to realize historic rates of return. Although we carry insurance on the vast majority of our assets, insurance may be inadequate to cover our loss and in some instances, we have been unable to obtain insurance on some of our assets on commercially reasonable terms, if at all. If we incur a significant disruption in our operations or a significant liability for which we were not fully insured, our financial condition, results of operations and ability to make distributions to our unitholders could be materially adversely affected.

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, to enable us to continue to make cash distributions to holders of our common units at our current distribution rate.

The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees we charge and the margins we realize for our services;
- the prices of, level of production of, and demand for natural gas, condensate, NGLs and propane;
- the success of our commodity and interest rate hedging programs in mitigating fluctuations in commodity prices and interest rates;
- the volume and quality of natural gas we gather, compress, treat, process, transport and sell, and the volume of NGLs we process, transport, sell and store, and the volume of propane we transport, sell and store;
- the operational performance and efficiency of our assets, including our plants and equipment;
- the operational performance and efficiency of third-party processing, fractionation or other facilities that provide services to us;
- the relationship between natural gas, NGL and crude oil prices;
- the level of competition from other energy companies;
- the impact of weather conditions on the demand for natural gas, NGLs and propane;
- the level of our operating and maintenance and general and administrative costs; and
- prevailing economic conditions.

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

- the level of capital expenditures we make;
- the cost and form of payment for acquisitions;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets at reasonable rates;
- restrictions contained in our credit agreement and the indentures governing our notes;
- the timing of our producers' obligations to make volume deficiency payments to us;
- the amount of cash distributions we receive from our equity interests;
- the amount of cost reimbursements to our general partner;
- the amount of cash reserves established by our general partner; and
- new, additions to and changes in laws and regulations.

We have partial ownership interests in various joint ventures, including Southern Hills, Sand Hills, Discovery, the Mont Belvieu fractionators, Texas Express, Front Range and Panola which could adversely affect our ability to operate and control these entities. In addition, we may be unable to control the amount of cash we will receive from the operation of these entities and we could be required to contribute significant cash to fund our share of their operations, which could adversely affect our ability to distribute cash to our unitholders.

Our inability, or limited ability, to control the operations and management of joint ventures in which we have a partial ownership interest may mean that we will not receive the amount of cash we expect to be distributed to us. In addition, for joint ventures in which we have a minority ownership interest, we will be unable to control ongoing operational decisions, including the incurrence of capital expenditures that we may be required to fund. Specifically,

- we have limited ability to control decisions with respect to the operations of these joint ventures, including decisions with respect to incurrence of expenses and distributions to us;
- these joint ventures may establish reserves for working capital, capital projects, environmental matters and legal proceedings which would otherwise reduce cash available for distribution to us;

- these joint ventures may incur additional indebtedness, and principal and interest made on such indebtedness may reduce cash otherwise available for distribution to us; and
- these joint ventures may require us to make additional capital contributions to fund working capital and capital expenditures, our funding of which could reduce the amount of cash otherwise available for distribution.

All of these items could significantly and adversely impact our ability to distribute cash to our unitholders.

The amount of cash we have available for distribution to holders of our common units depends primarily on our cash flow and not solely on profitability.

Profitability may be significantly affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

Competition from alternative energy sources, conservation efforts and energy efficiency and technological advances may reduce the demand for propane.

Competition from alternative energy sources, including natural gas and electricity, has been increasing as a result of reduced regulation of many utilities. In addition, propane competes with heating oil primarily in residential applications. Propane is generally not competitive with natural gas in areas where natural gas pipelines already exist because natural gas is a less expensive source of energy than propane. The gradual expansion of natural gas distribution systems and availability of natural gas in the northeast, which has historically depended upon propane, could reduce the demand for propane, which could adversely affect the volumes of propane that we distribute. In addition, stricter conservation measures in the future or technological advances in heating, energy generation or other devices could reduce the demand for propane.

We do not own all of the land on which our pipelines, facilities and rail terminals are located, which may subject us to increased costs.

Upon contract lease renewal, we may be subject to more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights of way or if such rights of way lapse or terminate. Certain of our leases contain renewal provisions that allow for our continued use and access of the subject land and, although we review and renew our leases as a routine business matter, there may be instances where we may not be able to renew our contract leases on commercially reasonable terms or may have to commence eminent domain proceedings to establish our right to continue to use the land. We obtain the rights to construct and operate our pipelines, surface sites and rail terminals on land owned by third parties and governmental agencies for a specific period of time.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance.

Our operations, and the operations of third parties, are subject to many hazards inherent in the gathering, compressing, treating, processing, storing, transporting and fractionating, as applicable, of natural gas, propane and NGLs, including:

- damage to pipelines, plants, terminals, storage facilities and related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction, farm and utility equipment;
- leaks of natural gas, propane, NGLs and other hydrocarbons from our pipelines, plants, terminals, or storage facilities, or losses of natural gas, propane or NGLs as a result of the malfunction of equipment or facilities;
- contaminants in the pipeline system;
- fires and explosions; and
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. We are not fully insured against all risks inherent to our business, including offshore wind. Although we insure most of our underground pipeline systems against property damage, certain of our gathering pipelines are not covered. We are not insured against all environmental accidents that might occur, which may include toxic tort claims, other than those considered to be sudden and accidental. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage, or may become prohibitively expensive, and we may elect not to carry such a policy.

Our business could be negatively impacted by security threats, including cybersecurity threats, terrorist attacks, the threat of terrorist attacks, sustained military campaigns and related disruptions.

We face cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable. Cybersecurity threats are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability.

We face the threat of future terrorist attacks on both our industry in general and on us, including the possibility that infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror. The increased security measures we have taken as a precaution against possible terrorist attacks have resulted in increased costs to our business. Any physical damage to facilities resulting from acts of terrorism may not be covered, or covered fully, by insurance. We may be required to expend material amounts of capital to repair any facilities, the expenditure of which could adversely affect our business and cash flows. Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

Due to our lack of industry diversification, adverse developments in our midstream operations or operating areas would reduce our ability to make distributions to our unitholders.

We rely on the cash flow generated from our midstream energy businesses, and as a result, our financial condition depends upon prices of, and continued demand for, natural gas, propane, condensate and NGLs. Due to our lack of diversification in industry type, an adverse development in one of these businesses, may have a significant impact on our company.

The amount of natural gas we gather, compress, treat, process, transport, sell and store, or the NGLs we produce, fractionate, transport, sell and store, may be reduced if the pipelines and storage fractionation facilities to which we deliver the natural gas or NGLs are capacity constrained and cannot, or will not, accept the natural gas or NGLs.
The natural gas we gather, compress, treat, process, transport, sell and store is delivered into pipelines for further delivery to end-users. If these pipelines are capacity constrained and cannot, or will not, accept delivery of the gas due to downstream constraints on the pipeline or changes in interstate pipeline gas quality specifications, we may be forced to limit or stop the flow of gas through our pipelines and processing and treating facilities. In addition, interruption of pipeline service upstream of our processing facilities would limit or stop flow through our processing and fractionation facilities. Likewise, if the pipelines into which we deliver NGLs are interrupted, we may be limited in, or prevented from conducting, our NGL transportation operations. Any number of factors beyond our control could cause such interruptions or constraints on pipeline service, including necessary and scheduled maintenance, or unexpected damage to the pipelines. Because our revenues and net operating margins depend upon (i) the volumes of natural gas we process, gather and transmit, (ii) the throughput of NGLs through our transportation, fractionation and storage facilities and (iii) the volume of natural gas we gather and transport, any reduction of volumes could adversely affect our operations and cash flows available for distribution to our unitholders.

Risks Inherent in an Investment in Our Common Units

Conflicts of interest may exist between our individual unitholders and DCP Midstream, LLC, our general partner, which has sole responsibility for conducting our business and managing our operations.

DCP Midstream, LLC owns and controls our general partner. Some of our general partner's directors and all of its executive officers are directors or executive officers of DCP Midstream, LLC or its owners. Therefore, conflicts of interest may arise between DCP Midstream, LLC and its affiliates and our unitholders. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires DCP Midstream, LLC to pursue a business strategy that favors us. DCP Midstream, LLC's directors and officers have a fiduciary duty to make these decisions in the best interests of the owners of DCP Midstream, LLC, which may be contrary to our interests;
- our general partner is allowed to take into account the interests of parties other than us, such as DCP Midstream, LLC and its affiliates, in resolving conflicts of interest;

43

- DCP Midstream, LLC and its affiliates, including Phillips 66 and Spectra Energy, are not limited in their ability to compete with us. Please read "DCP Midstream, LLC and its affiliates are not limited in their ability to compete with us" below;
- once certain requirements are met, our general partner may make a determination to receive a quantity of our Class B units in exchange for resetting the target distribution levels related to its incentive distribution rights without the approval of the special committee of our general partner or our unitholders;
- our general partner has limited its liability and reduced its fiduciary duties, and has also restricted the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- our general partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities and reserves, each of which can affect the amount of cash that is distributed to unitholders;
- our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our general partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, is entitled to be indemnified by us;
- our general partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 80% of the common units;
- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

DCP Midstream, LLC and its affiliates are not limited in their ability to compete with us, which could cause conflicts of interest and limit our ability to acquire additional assets or businesses, which in turn could adversely affect our results of operations and cash available for distribution to our unitholders.

Neither our partnership agreement nor the Services and Employee Secondment Agreement, or the Services Agreement, between us and DCP Midstream, LLC prohibits DCP Midstream, LLC and its affiliates, including Phillips 66 and Spectra Energy, from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, DCP Midstream, LLC and its affiliates, including Phillips 66 and Spectra Energy, may acquire, construct or dispose of additional midstream or other assets in the future, without any obligation to offer us the opportunity to purchase or construct any of those assets. Each of these entities is a large, established participant in the midstream energy business, and each has significantly greater resources than we have, which factors may make it more difficult for us to compete with these entities with respect to commercial activities as well as for acquisition candidates. As a result, competition from these entities could adversely impact our results of operations and cash available for distribution.

Cost reimbursements due to our general partner and its affiliates for services provided, which will be determined by our general partner, will be material.

Pursuant to the Services Agreement, DCP Midstream, LLC and its affiliates will receive reimbursement for the payment of operating expenses related to our operations and for the provision of various general and administrative services for our benefit. Payments for these services will be material. In addition, under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. These factors may reduce the amount of cash otherwise available for distribution to our unitholders.

Our partnership agreement limits our general partner’s fiduciary duties to holders of our common units.

Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owner, DCP Midstream, LLC. Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty laws. For example, our partnership agreement permits our general partner to make a number of decisions either in its individual capacity, as opposed to in its capacity as our general partner or otherwise free of fiduciary duties to us and our unitholders. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include:

- the exercise of its right to reset the target distribution levels of its incentive distribution rights at higher levels and receive, in connection with this reset, a number of Class B units that are convertible at any time following the first anniversary of the issuance of these Class B units into common units;
- its limited call right;
- its voting rights with respect to the units it owns;
- its registration rights; and
- its determination whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

By purchasing a common unit, a common unitholder will 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 common units 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 our unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty. For example, our partnership agreement:

- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning it believed the decision was in the best interests of our partnership;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the special committee of the board of directors of our general partner and not involving a vote of our unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or must be “fair and reasonable” to us, as determined by our general partner in good faith and that, in determining whether a transaction or resolution is “fair and reasonable,” our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons 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.

Our general partner may elect to cause us to issue Class B units to it in connection with a resetting of the target distribution levels related to our general partner’s incentive distribution rights without the approval of the special committee of our general partner or holders of our common units. This may result in lower distributions to holders of our common units in certain situations.

Our general partner currently has the right to reset the initial cash target distribution levels at higher levels based on the distribution at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common unit for the two fiscal quarters immediately preceding the reset election, or the reset minimum quarterly distribution, and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution amount. Currently, our distribution to our general partner related to its incentive distribution rights is at the highest level.

In connection with resetting these target distribution levels, our general partner will be entitled to receive a number of Class B units. The Class B units will be entitled to the same cash distributions per unit as our common units and will be convertible into an equal number of common units. The number of Class B units to be issued will be equal to that number of common units whose aggregate quarterly cash distributions equaled the average of the distributions to our general partner on the incentive distribution rights in the prior two quarters. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that our general partner could exercise this reset election at a time when it is experiencing, or may be expected to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued our Class B units, which are entitled to receive cash distributions from us on the same priority as our common units, rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, in certain situations, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new Class B units to our general partner in connection with resetting the target distribution levels related to our general partner incentive distribution rights.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Our unitholders do not elect our general partner or its board of directors, and have no right to elect our general partner or its board of directors on an annual or other continuing basis. The board of directors of our general partner are chosen by the members of our general partner. As a result of these limitations, the price at which the common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Our common units may experience price volatility.

Our common unit price has experienced volatility in the past, and volatility in the price of our common units may occur in the future as a result of any of the risk factors contained herein and the risks described in our other public filings with the SEC. For instance, our common units may experience price volatility as a result of changes in investor sentiment with respect to our competitors, our business partners and our industry in general, which may be influenced by volatility in prices for NGLs, natural gas and crude oil. In addition, the securities markets have from time to time experienced significant price and volume fluctuations that are unrelated to the operating performance of particular companies but affect the market price of their securities. These market fluctuations may also materially and adversely affect the market price of our common units.

Even if holders of our common units are dissatisfied, they may be unable to remove our general partner without its consent.

The unitholders may be unable to remove our general partner without its consent because our general partner and its affiliates own a significant percentage of our outstanding units. The vote of the holders of at least 66 2/3% of all outstanding units voting together as a single class is required to remove the general partner. As of December 31, 2016, our general partner and its affiliates owned approximately 21% of our outstanding common units and, immediately following the Transaction, our general partner and its affiliates owned approximately 37% of our outstanding common units.

Our partnership agreement restricts the voting rights of our unitholders owning 20% or more of our common units.

Our unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of our unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting our unitholders' ability to influence the manner or direction of management.

If we are deemed an "investment company" under the Investment Company Act of 1940, it would adversely affect the price of our common units and could have a material adverse effect on our business.

Our assets include a 40% interest in the Discovery system, a 33.33% interest in Front Range, a 20% interest in the Mont Belvieu 1 fractionator, a 15% interest in Panola, a 12.5% interest in the Mont Belvieu Enterprise fractionator and a 10% interest in Texas Express, which, along with certain of our other assets, may be deemed to be “investment securities” within the meaning of the Investment Company Act of 1940. In the future, we may acquire additional minority owned interests in joint ventures that could be deemed "investment securities." If a sufficient amount of our assets are deemed to be “investment securities” within the meaning of the Investment Company Act, we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the SEC or modify our organizational structure or our contract rights to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us or our affiliates. The occurrence of some or all of these events may have a material adverse effect on our business.

Moreover, treatment of us as an investment company would prevent our qualification as a partnership for federal income tax purposes in which case we would be treated as a corporation for federal income tax purposes, and be subject to federal income tax at the corporate tax rate, significantly reducing the cash available for distributions. Additionally, distributions to our unitholders would be taxed again as corporate distributions and none of our income, gains, losses or deductions would flow through to our unitholders.

Additionally, as a result of our desire to avoid having to register as an investment company under the Investment Company Act, we may have to forego potential future acquisitions of interests in companies that may be deemed to be investment securities within the meaning of the Investment Company Act or dispose of our current interests in any of our assets that are deemed to be "investment securities."

Control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, under our partnership agreement the owners of our general partner may pledge, impose a lien or transfer all or a portion of their respective ownership interest in our general partner to a third party. Any new owners of our general partner would then be in a position to replace the board of directors and officers of the general partner with its own choices and thereby influence the decisions taken by the board of directors and officers.

We may issue additional units without our unitholders' approval, which would dilute our unitholders' existing ownership interests.

Our partnership agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:
- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Our general partner including its affiliates may sell units in the public or private markets, which could reduce the market price of our outstanding common units.

If our general partner or its affiliates holding unregistered units were to dispose of a substantial portion of these units in the public market, whether in a single transaction or series of transactions, it could reduce the market price of our outstanding common units. In addition, these sales, or the possibility that these sales may occur, could make it more difficult for us to sell our common units in the future.

Our general partner has a limited call right that may require our unitholders to sell their units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, our unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Our unitholders may also incur a tax liability upon a sale of their units.

The liability of holders of limited partner interests may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. Holders of limited partner interests could be liable for any and all of our obligations as if such holder were a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state’s partnership statute; or

- the right of holders of limited partner interests to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, our unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable for the obligations of the assignor to make contributions to the partnership that are known to the substituted limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our being subject to minimal entity-level taxation by individual states. If the Internal Revenue Service, or IRS, were to treat us as a corporation for federal income tax purposes, or we become subject to a material amount of entity-level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to our unitholders.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS regarding our status as a partnership.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe based upon our current operations that we will be treated as a corporation, the IRS could disagree with the positions we take or a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions to a unitholder would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to the unitholder. Because a tax would be imposed upon us as a corporation, our cash available for distribution to a unitholder would be substantially reduced. Therefore, treatment of us as a corporation for federal tax purposes would result in a material reduction in the anticipated cash flow and after-tax return to a unitholder, likely causing a substantial reduction in the value of our common units.

The partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution levels will be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units, may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Moreover, any such modification could make it more difficult or impossible for us to meet the exception that allows publicly traded partnerships that generate qualifying income to be treated as partnerships (rather than corporations) for federal income tax purposes, affect or cause us to change our business activities, or affect the tax consequences of an investment in our common units. The U.S. Treasury Department issued final regulations interpreting the scope of activities that generate qualifying income under Section 7704 of the Internal Revenue Code of 1986, as amended, or the Code. We believe that the income we currently treat as qualifying income satisfies the requirements for qualifying income under the final regulations.

Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation, which would reduce the cash available for distribution to our unitholders. For example, we are required to pay the State of Texas a margin tax that is assessed at 0.75% of taxable margin apportioned to Texas. The partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution levels will be adjusted to reflect the impact of that law on us.

Changes in tax laws could adversely affect our performance.

We are subject to extensive tax laws and regulations, with respect to federal, state and foreign income taxes and transactional taxes such as excise, sales/use, payroll, franchise and ad valorem taxes. 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.

If tax authorities contest the tax positions we take, the market for our common units may be adversely impacted, and the cost of any contest with a tax authority would reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. Tax authorities may adopt positions that differ from the conclusions of our counsel or from the positions we take, and the tax authority's positions may ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel’s conclusions or the positions we take. A court may not agree with some or all of our counsel’s conclusions or positions we take. Any contest with a tax authority, and the outcome of any such contest, may increase a unitholder’s tax liability and result in adjustment to items unrelated to us and could materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with any tax authority will be borne indirectly by our unitholders and our general partner because such costs will reduce our cash available for distribution.

Recently enacted legislation applicable to us for taxable years beginning after December 31, 2017 alters the procedures for auditing large partnerships and also alters the procedures for assessing and collecting taxes due (including applicable penalties and interest) as a result of an audit. Unless we are eligible to (and choose to) elect to issue revised Schedules K-1 to our partners with respect to an audited and adjusted return, the IRS may assess and collect taxes (including any applicable penalties and interest) directly from us in the year in which the audit is completed under the new rules. If we are required to pay taxes, penalties and interest as the result of audit adjustments, cash available for distribution to our unitholders may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during the audited taxable year.

Our unitholders may be required to pay taxes on income from us even if the unitholders do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income, which could be different in amount than the cash we distribute, unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the tax liability that results from that income.

Certain actions that we may take, such as issuing additional units, may increase the federal income tax liability of unitholders.

In the event we issue additional units or engage in certain other transactions in the future, the allocable share of nonrecourse liabilities allocated to the unitholders will be recalculated to take into account our issuance of any additional units. Any reduction in a unitholder’s share of our nonrecourse liabilities will be treated as a distribution of cash to that unitholder and will result in a corresponding tax basis reduction in a unitholder’s units. A deemed cash distribution may, under certain circumstances, result in the recognition of taxable gain by a unitholder, to the extent that the deemed cash distribution exceeds such unitholder’s tax basis in its units.

In addition, the federal income tax liability of a unitholder could be increased if we dispose of assets or make a future offering of units and use the proceeds in a manner that does not produce substantial additional deductions, such as to repay indebtedness currently outstanding or to acquire property that is not eligible for depreciation or amortization for federal income tax purposes or that is depreciable or amortizable at a rate significantly slower than the rate currently applicable to our assets.

Tax gain or loss on disposition of common units could be more or less than expected.

If a unitholder sells its common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized and the unitholder's tax basis in those common units. Because distributions to a unitholder in excess of the total net taxable income allocated to it for a common unit decreases its tax basis in that common unit, the amount, if any, of such prior excess distributions with respect to the units sold will, in effect, become taxable income to the unitholder if the common unit is sold at a price greater than their tax basis in that common unit, even if the price is less than their original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder’s share of our nonrecourse liabilities, if a unitholder sells its units, the unitholder may incur a tax liability in excess of the amount of cash the unitholder receives from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as individual retirement accounts, or IRAs, other retirement plans and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income, which may be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal tax returns and pay tax on their share of our taxable income. If a unitholder is a tax-exempt entity or a non-U.S. person, the unitholder should consult its tax advisor before investing in our common units.

We treat each purchaser of our common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to the unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders’ tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The U.S. Treasury Department recently adopted final regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. These regulations do not specifically authorize the proration method we have previously used. If the IRS were to challenge our proration method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may be required to recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and such unitholder may be required to recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing and lending their units.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, subsequent purchasers of common units may have a greater portion of their adjustment under Section 743(b) of the Code allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We experienced a tax technical termination as of December 30, 2016. Our termination, among other things, resulted in the closing of our taxable year for all unitholders, which will result in us filing two tax returns (and our unitholders could receive two Schedule K-1s if relief from the IRS is not granted, as described below) for one calendar year. The termination also is expected to result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Under current law, the termination does not affect our classification as a partnership for federal income tax purposes, but instead, after our termination we are treated as a new partnership for tax purposes. As a new partnership, we must make new tax elections. The IRS has announced a relief procedure for publicly traded partnerships that terminate in this manner, whereby if a publicly traded partnership that has terminated requests and the IRS grants special relief, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year, notwithstanding two partnership tax years resulting from the termination. We are in the process of securing the special relief from the IRS and expect to issue one Schedule K-1 to our unitholders for the tax year ended December 31, 2016.

51

Unitholders may be subject to state and local taxes and return filing requirements in states where they do not live as a result of investing in our units.

In addition to federal income taxes, unitholders may be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if the unitholders do not live in any of those jurisdictions. Unitholders may be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, the unitholder may be subject to penalties for failure to comply with those requirements. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax or an entity level tax. It is each unitholder's responsibility to file all United States federal, foreign, state and local tax returns. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in our common units.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

For details on our plants, fractionation and storage facilities, propane terminals and pipeline systems, please read "Item 1 Business - Our Business". We believe that our properties are generally in good condition, well maintained and are suitable and adequate to carry on our business at capacity for the foreseeable future.

Our real property falls into two categories: (1) parcels that we own in fee; and (2) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. Portions of the land on which our plants and other major facilities are located are owned by us in fee title, and we believe that we have satisfactory title to these lands. The remainder of the land on which our plant sites and major facilities are located are held by us pursuant to ground leases between us, as lessee, and the fee owner of the lands, as lessors. We, or our predecessors, have leased these lands for many years without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that we have satisfactory leasehold estates to such lands. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our title to any material lease, easement, right-of-way, permit or lease, and we believe that we have satisfactory title to all of our material leases, easements, rights-of-way, permits and licenses.

Our principal executive offices are located at 370 17th Street, Suite 2500, Denver, Colorado 80202, our telephone number is 303-595-3331 and our website address is www.dcpmidstream.com.

Item 3. Legal Proceedings

We are not a party to any significant legal proceedings, but are a party to various administrative and regulatory proceedings and commercial disputes that have arisen in the ordinary course of our business. Management currently believes that the ultimate resolution of these matters, taken as a whole, and after consideration of amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect upon our consolidated results of operations, financial position or cash flows. For more information, please read "Environmental Matters."

Environmental — The operation of pipelines, plants and other facilities for gathering, transporting, processing, treating, fractionating, or storing natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with laws and regulations at the federal, state and, in some cases, local levels that relate to worker safety, air and water quality, solid and hazardous waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities incorporates compliance with environmental laws and regulations, worker safety standards, and safety standards applicable to our various facilities. In addition, there is increasing focus (i) from city, state and federal regulatory officials and through litigation, on hydraulic fracturing and the real or perceived environmental impacts of this technique, which indirectly presents some risk to our available supply of natural gas and the resulting supply of NGLs, (ii) from federal regulatory agencies regarding pipeline system safety which could impose additional regulatory burdens and increase the cost of our operations, and (iii) from state and federal regulatory officials regarding the emission of greenhouse gases which could impose regulatory burdens and increase the cost of our operations. Failure to comply with these various health, safety and environmental laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these existing laws and regulations will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Item 4. Mine Safety Disclosures
Not applicable.

PART II

Item 5. Market for Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Common Units

Market Information

On January 23, 2017, in connection with the Name Change, the ticker symbol for our common units representing limited partner interests listed on the New York Stock Exchange, or the NYSE, was changed from "DPM" to "DCP". The following table sets forth intra-day high and low sales prices of the common units, as reported by the NYSE, as well as the amount of cash distributions declared per quarter for 2016 and 2015.

Quarter Ended	High	Low	Distribution Per Common Unit
December 31, 2016	39.43	31.03	0.78
September 30, 2016	36.21	31.23	0.78
June 30, 2016	38.15	24.70	0.78
March 31, 2016	28.53	15.09	0.78
December 31, 2015	30.00	19.26	0.78
September 30, 2015	34.04	22.04	0.78
June 30, 2015	41.75	30.43	0.78
March 31, 2015	47.71	35.10	0.78

As of February 3, 2017, there were approximately 42 unitholders of record of our common units. This number does not include unitholders whose units are held in trust by other entities.

Distributions of Available Cash

General - Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our Available Cash (defined below) to unitholders of record on the applicable record date, as determined by our general partner.

Definition of Available Cash - Available Cash, for any quarter, consists of all cash and cash equivalents on hand at the end of that quarter:

- less the amount of cash reserves established by our general partner to:
- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments or other agreements; or
- provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters;
- plus, if our general partner so determines, all or a portion of cash and cash equivalents on hand on the date of determination of Available Cash for the quarter.

Minimum Quarterly Distribution - The Minimum Quarterly Distribution, as set forth in the partnership agreement, is $0.35 per unit per quarter, or $1.40 per unit per year. Our current quarterly distribution is $0.78 per unit, or $3.12 per unit annualized. There is no guarantee that we will maintain our current distribution or pay the Minimum Quarterly Distribution on the units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Requirements - Liquidity and Capital Resources" for a discussion of the restrictions included in our Amended and Restated Credit Agreement that may restrict our ability to make distributions.

General Partner Interest and Incentive Distribution Rights - As of December 31, 2016, the general partner was entitled to a percentage of all quarterly distributions equal to its general partner interest of approximately 0.3% and limited partner interest of 1.7%. The general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. The general partner's interest may be reduced if we issue additional units in the

54

future and our general partner does not contribute a proportionate amount of capital to us to maintain its current general partner interest.

The incentive distribution rights held by our general partner entitle it to receive an increasing share of Available Cash as pre-defined distribution targets have been achieved. Currently, our distribution to our general partner related to its incentive distribution rights is at the highest level. Our general partner's incentive distribution rights have not been reduced as a result of our common unit offerings, and will not be reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its current general partner interest. Notwithstanding the foregoing, on January 1, 2017, the General Partner, in its capacity as the general partner of the partnership, entered into the Third Amendment to the Partnership Agreement. The Third Amendment to the Partnership Agreement includes terms that amend the Partnership Agreement to cause the incentive distributions payable to the holders of the partnership's incentive distribution rights with respect to the fiscal years 2017, 2018 and 2019 to, in certain circumstances, be reduced in an amount up to $100 million per fiscal year as necessary to provide that the Distributable Cash Flow of the partnership (as adjusted) during such year meets or exceeds the amount of distributions made by the partnership (as adjusted) to the partners of the partnership with respect to such year.

Please read the Distributions of Available Cash section in Note 14 of the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data" for more details about the distribution targets and their impact on the general partner's incentive distribution rights.

On January 26, 2017, we announced that the board of directors of DCP Midstream GP, LLC declared a quarterly distribution of $0.78 per unit, which was paid on February 14, 2017, to unitholders of record on February 7, 2017, except that the owners of the partnership's general partner will receive distributions on the units issued on January 1, 2017 beginning with the first quarter 2017 declared distribution.

Securities Authorized for Issuance Under Equity Compensation Plans

The information relating to our equity compensation plans required by Item 5 is incorporated by reference to such information as set forth in Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters" contained herein.

Item 6. Selected Financial Data

The following table shows our selected financial data for the periods and as of the dates indicated, which is derived from our consolidated financial statements. The information contained herein 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 Form 10-K.

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 on our critical accounting estimates is included in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations".

The table should also be read together with Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

The following table shows our selected financial and operating data for the periods and as of the dates indicated, which is derived from our consolidated financial statements.

	Year Ended December 31,				
	2016	2015	2014 (a)	2013 (a)	2012 (a)
	(Millions, except per unit amounts)				
Statements of Operations Data:					
Sales of natural gas, propane, NGLs and condensate	$1,093	$1,442	$3,143	$2,763	$2,520
Transportation, processing and other	424	371	345	271	234
(Losses) gains from commodity derivative activity, net (b) (c)	(20)	85	154	17	70
Total operating revenues	1,497	1,898	3,642	3,051	2,824
Operating costs and expenses:					
Purchases of natural gas, propane and NGLs	946	1,246	2,795	2,426	2,215
Operating and maintenance expense	183	214	216	215	197
Depreciation and amortization expense	122	120	110	95	91
General and administrative expense	88	85	64	63	75
Goodwill impairment	—	82	—	—	—
Other expense, net	7	4	3	8	—
Gain on sale of assets	(47)	—	—	—	—
Total operating costs and expenses	1,299	1,751	3,188	2,807	2,578
Operating income	198	147	454	244	246
Interest expense	(94)	(92)	(86)	(52)	(42)
Earnings from unconsolidated affiliates (d)	214	173	75	33	26
Income before income taxes	318	228	443	225	230
Income tax benefit (expense)	—	5	(6)	(8)	(1)
Net income	318	233	437	217	229
Net income attributable to noncontrolling interests	(6)	(5)	(14)	(17)	(13)
Net income attributable to partners	$312	$228	$423	$200	$216
Net income attributable to predecessor operations (e)	—	—	(6)	(25)	(51)
General partner interest in net income	(124)	(124)	(114)	(70)	(41)
Net income allocable to limited partners	$188	$104	$303	$105	$124
Net income per limited partner unit-basic and diluted	$1.64	$0.91	$2.84	$1.34	$2.28

	Year Ended December 31,				
	2016	2015	2014 (a)	2013 (a)	2012 (a)
	(Millions, except per unit amounts)				
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$3,272	$3,476	$3,347	$3,046	$2,592
Total assets	$5,161	$5,477	$5,722	$4,567	$3,645
Accounts payable	$139	$117	$223	$275	$223
Long-term debt	$1,750	$2,424	$2,044	$1,590	$1,620
Partners' equity	$2,601	$2,772	$2,993	$1,985	$1,447
Noncontrolling interests	$32	$33	$33	$228	$189
Total equity	$2,633	$2,805	$3,026	$2,213	$1,636
Other Information:					
Cash distributions declared per unit	$3.1200	$3.1200	$3.0525	$2.8630	$2.7000
Cash distributions paid per unit	$3.1200	$3.1200	$3.0050	$2.8200	$2.6600

(a) Includes the effect of the following acquisitions prospectively from their respective dates of acquisition: (1) the remaining 49.9% interest in East Texas acquired from DCP Midstream, LLC in January 2012; (2) a 10% ownership interest in the Texas Express Pipeline acquired from Enterprise Products Partners, L.P. in April 2012; (3) a 12.5% interest in the Enterprise fractionator and a 20% interest in the Mont Belvieu 1 fractionator, acquired from DCP Midstream, LLC in July 2012; (4) the Crossroads processing plant and 50% interest in CrossPoint Pipeline, LLC, acquired from Penn Virginia Resource Partners, L.P. in July 2012; (5) the O'Connor plant acquired from DCP

56

Midstream, LLC in August 2013; (6) the Front Range pipeline acquired from DCP Midstream, LLC in August 2013 and (7) a 33.33% interest in each the Southern Hills and Sand Hills pipelines, acquired from DCP Midstream, LLC in March 2014.

(b) Includes the effect of the commodity derivative hedge instruments related to the Eagle Ford system, of which 33.33% was acquired from DCP Midstream, LLC in November 2012 and 46.67% was acquired in March 2013; the Goliad plant, of which 33.33% was acquired from DCP Midstream, LLC in December 2012 and 46.67% was acquired in March 2013 and the Southeast Texas storage business acquired from DCP Midstream, LLC in March 2012.

(c) Prior to the acquisition of the remaining 49.9% limited liability company interest in East Texas in January 2012, we hedged our proportionate ownership of East Texas. Results shown include the unhedged portion of East Texas owned by DCP Midstream, LLC. Our consolidated results depict 66.67% unhedged through March 2012 corresponding with DCP Midstream, LLC's ownership interest in Southeast Texas. Our consolidated results depict 100% of the Eagle Ford system unhedged through October 2012, and 66.67% from November 2012 through March 2013, and 20% from April 2013 through March 2014 corresponding with DCP Midstream, LLC's ownership interest in the Eagle Ford system.

(d) Includes our proportionate share of the earnings of our unconsolidated affiliates. Earnings include the amortization of the net difference between the carrying amount of the investments and the underlying equity of the entities.

(e) Our consolidated financial statements include the historical assets, liabilities and results of operations of assets acquired from DCP Midstream, LLC, transactions between entities under common control, representing a change in reporting entity. Earnings for periods prior to these dropdowns are allocated to predecessor operations to derive net income allocable to limited partners. Accordingly, net income attributable to predecessor operations includes the remaining 66.67% interest in Southeast Texas and commodity derivative hedge instruments prior to the date of our acquisition from DCP Midstream, LLC in March 2012; the initial 33.33% interest in the Eagle Ford system prior to the date of our acquisition from DCP Midstream, LLC in November 2012; the additional 46.67% interest in the Eagle Ford system prior to the date of our acquisition from DCP Midstream, LLC in March 2013 and the Lucerne 1 plant prior to the date of our acquisition from DCP Midstream, LLC in March 2014.

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

The following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our consolidated financial statements and notes included elsewhere in this Annual Report on Form 10-K. Unless the context clearly indicates otherwise, the portions of this Item 7 containing current and forward-looking information reflects the registrant following the consummation of the Transaction and the portions containing historical information, our historical operating results or that discuss our operating segments reflects the registrant prior to consummation of the Transaction.

Overview

We are a Delaware limited partnership formed by DCP Midstream, LLC to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. In 2016, prior to the Transaction, our operations were organized into three business segments: Natural Gas Services, NGL Logistics and Wholesale Propane Logistics. Our business is impacted by commodity prices and volumes. We mitigate a portion of commodity price risk on an overall Partnership basis by growing our fee based assets and through a hedging program on volumes of throughput and sales of natural gas, NGLs and condensate. Various factors impact both commodity prices and volumes, and as indicated in Item 7A "Quantitative and Qualitative Disclosures about Market Risk," we have sensitivities to certain cash and non-cash changes in commodity prices. If commodity prices weaken for a sustained period, our natural gas throughput and NGL volumes may be impacted, particularly as producers are curtailing or redirecting drilling. Drilling activity levels vary by geographic area; we will continue to target our strategy in geographic areas where we expect producer drilling activity.

A decline in commodity prices has resulted in a decrease in exploration and development activities in certain fields served by our gas gathering and residue gas and NGL pipeline transportation systems, and our natural gas processing and treating plants, which could lead to further reduced utilization of these assets.

Our long-term view is that commodity prices will be at levels that we believe will support growth in natural gas, condensate and NGL production. We believe that future commodity prices will be influenced by North American supply deliverability, the severity of winter and summer weather, the level of North American production and drilling activity by exploration and production companies and the balance of trade between imports and exports of liquid natural gas, NGLs and crude oil.

NGL prices are impacted by the demand from petrochemical and refining industries and export facilities. The petrochemical industry has been making significant investment in building and expanding facilities to convert chemical plants from a heavier oil-based feedstock to lighter NGL-based feedstocks, including ethane. This increased demand in future years should provide support for the increasing supply of ethane. Prior to those facilities commencing operations, ethane prices could remain weak with supply in excess of demand. In addition, export facilities are being expanded and built, which provide support for the increasing supply of NGLs. Although there can be, and has been, volatility in NGL prices, longer term we believe there will be sufficient demand in NGLs to support increasing supply.

Although we have seen a number of recent bankruptcies by producers, we believe our contract structure with our producers protects us from a credit perspective since we generally hold the product, sell it and withhold our fees prior to remittance of payments to the producer. Currently our top 20 producers account for a majority of the total natural gas that we gather and process and of these top 20 producers, five are investment grade and the remainder are not investment grade.

In addition to the U.S. financial markets, many businesses and investors continue to monitor global economic conditions. Uncertainty abroad may contribute to volatility in domestic financial and commodity markets.

We believe we are positioned to withstand current and future commodity price volatility as a result of the following:

- Our growing fee-based business represents a significant portion of our estimated margins.
- We have positive operating cash flow from our well-positioned and diversified assets.
- We have a well-defined and targeted hedging program.
- We prudently manage our capital expenditures and focus on fee-based growth projects.
- We believe we have a strong capital structure and balance sheet.
- We believe we have access to sufficient capital.

Increased activity levels in liquids rich gas basins combined with access to capital markets at relatively low costs have historically enabled us to execute our growth strategy. Our targeted strategy may take numerous forms such as organic build opportunities within our footprint, joint venture opportunities, and acquisitions. Growth opportunities will be evaluated in cooperation with producers based on the expected level of drilling activity in these geographic regions and the impacts of higher costs of capital.

Some of our growth projects include the following:

- The construction of a 200 MMcf/d cryogenic natural gas processing plant, Mewbourn 3 plant, located in the DJ Basin, which is expected to be in service in late 2018.
- The Sand Hills pipeline mainline capacity expansion was placed into service during the second quarter of 2016. We are currently expanding the Sand Hills pipeline capacity to its full capacity of 365 MBbls/d, and the expansion is expected to be in service by the end of 2017.
- On February 1, 2016, we began to participate in earnings for our 15% interest in the Panola intrastate NGL pipeline which completed an expansion in the third quarter of 2016.
- In the first quarter of 2016, we completed construction on our Grand Parkway gathering system in the DJ Basin. We are currently expanding our Grand Parkway gathering system, and the expansion is expected to be in service by the end of 2018.

On December 30, 2016, the partnership entered into a Contribution Agreement with DCP Midstream, LLC and DCP Midstream Operating, LP. On January 1, 2017, DCP Midstream, LLC contributed to us: (i) its ownership interests in all of its subsidiaries owning operating assets, and (ii) $424 million of cash. In consideration of the partnership's receipt of the Contributions, (i) the partnership issued 28,552,480 common units to DCP Midstream, LLC and 2,550,644 general partner units to DCP Midstream GP, LP, the General Partner, in a private placement and (ii) the Operating Partnership assumed $3,150 million of DCP Midstream, LLC's debt.

As part of our ongoing effort to create efficiencies, reduce costs and transform our business, DCP Midstream, LLC, announced an approximate 10 percent headcount reduction in April 2016, which involved the elimination of certain operational and corporate positions. This has not impacted the operation of our assets.

On April 28, 2016, the unitholders of the partnership approved the DCP Midstream Partners, LP 2016 Long-Term Incentive Plan (the "2016 LTIP"), which replaced the 2005 long-term incentive plan that expired pursuant to its terms at the end of 2015 (the "2005 LTIP"). Any outstanding awards under the 2005 plan will remain outstanding and settle according to the terms of such grant. The 2016 LTIP authorizes up to 900,000 common units to be available for issuance under awards to employees, officers, and non-employee directors of the General Partner and its affiliates. Awards under the 2016 LTIP may include unit options, phantom units, restricted units, distribution equivalent rights, unit bonuses, common unit awards, and performance awards. The 2016 LTIP will expire on the earlier of the date it is terminated by the board of directors of the General Partner or the date that all common units available under the plan have been paid or issued. We believe the 2016 LTIP is an important tool to attract and retain qualified individuals who are essential to the future success of the partnership.

We announced a quarterly distribution of $0.78 per unit for the fourth quarter of 2016. This distribution remains unchanged from the previous quarter and the fourth quarter of 2015.

General Trends and Outlook

During 2017, our strategic objectives will continue to focus on maintaining stable Distributable Cash Flows from our existing assets and executing on opportunities to sustain our long-term Distributable Cash Flows in light of the significant changes to our business resulting from the Transaction. We believe the key elements to stable Distributable Cash Flows are the diversity of our asset portfolio, our fee-based business which represents a significant portion of our estimated margins, plus our hedged commodity position, the objective of which is to protect against downside risk in our Distributable Cash Flows.

We incur capital expenditures for our consolidated entities and our unconsolidated affiliates. Our 2017 plan includes maintenance capital expenditures of between $100 million and $145 million, and approved expansion capital expenditures between $325 million and $375 million, for the year ending December 31, 2017. Expansion capital expenditures include the construction of the Mewbourn 3 plant and construction of Grand Parkway Phase 2 in our DJ Basin system, and the capacity expansion of the Sand Hills pipeline, which is shown as an investment in unconsolidated affiliates in our consolidated statements of cash flows.

We anticipate our business to continue to be affected by the following key trends. 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.

Commodity Price Environment - Our business is impacted by commodity prices. If commodity prices weaken for a sustained period, our natural gas throughput and NGL volumes may be impacted, particularly as producers are curtailing or redirecting drilling. Drilling activity levels vary by geographic area; we have observed decreases in drilling activity in certain regions, and increases in drilling activity in others. The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by drilling activity, which may be impacted by prevailing commodity prices. Commodity prices have been lower compared to historical periods and experienced significant volatility during recent years, as illustrated in Item 1A. Risk Factors - "Our cash flow is affected by natural gas, NGL and condensate prices." Despite recent short-term weakness, our long-term view is that commodity prices will be at levels that we believe will support continued growth in natural gas, condensate and NGL production.

Natural Gas Gathering and Processing Margins - Except for our fee-based contracts, which may be impacted by throughput volumes, our natural gas gathering and processing profitability is dependent upon commodity prices, natural gas supply, and demand for natural gas, NGLs and condensate. Commodity prices, which are impacted by the balance between supply and demand, have historically been volatile. Throughput volumes could decline should commodity prices and drilling levels continue to experience weakness. Our long-term view is that as industry conditions improve, commodity prices should support continued natural gas production in the United States. During 2016, petrochemical demand remained stable for NGLs as NGLs were a competitive feedstock when compared to crude oil derived feedstocks. We anticipate demand for NGLs by the petrochemical industry will continue in 2017 as chemical plants convert facilities from an oil-based feedstock to a NGL-based feedstock and as export facilities are brought into service. Although there can be, and has been, near-term volatility in NGL prices, longer term we believe there will be sufficient demand in NGLs to balance supply.

NGL Logistics - The volumes of NGLs transported on our pipelines, fractionated in our fractionation facilities and stored in our storage facility are dependent on the level of production of NGLs from processing plants connected to our assets. When natural gas prices are high relative to NGL prices, it is less profitable to process natural gas because of the higher value of natural gas compared to the value of NGLs and because of the increased cost of separating the NGLs from the natural gas. As a

result, we have experienced periods in the past, in which higher natural gas or lower NGL prices reduce the volume of NGLs extracted at plants connected to our NGL pipelines, fractionation and storage facilities and, in turn, lower the NGL throughput on our assets.
Wholesale Propane Supply and Demand - Due to our multiple propane supply sources, propane supply contractual arrangements, significant storage capabilities, and multiple terminal locations for wholesale propane delivery, we are generally able to provide our propane distribution customers with reliable supplies of propane during peak demand periods of tight supply, usually in the winter months when their customers consume the most propane for heating.

Factors That May Significantly Affect Our Results
Transfers of net assets between entities under common control that represent a change in reporting entity are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method. Accordingly, our consolidated financial statements have been adjusted to include the historical results of our Lucerne 1 plant for all periods presented, similar to the pooling method. The financial statements of our predecessor have been prepared from the separate records maintained by DCP Midstream, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessor had been operated as an unaffiliated entity.

Natural Gas Services Segment

Our results of operations for our Natural Gas Services segment are impacted by (1) the prices of and relationship between commodities such as NGLs, crude oil and natural gas, (2) increases and decreases in the volume and quality of natural gas that we gather and transport through our systems, which we refer to as throughput, (3) the associated Btu content of our system throughput and our related processing volumes, (4) the operating efficiency and reliability of our processing facilities, (5) potential limitations on throughput volumes arising from downstream and infrastructure capacity constraints, (6) the terms of our processing contract arrangements with producers, and (7) increases and decreases in the volume, price and basis differentials of natural gas associated with our natural gas storage and pipeline assets, as well as our underlying derivatives associated with these assets. This is not a complete list of factors that may impact our results of operations but, rather, are those we believe are most likely to impact those results.

Throughput and operating efficiency generally are driven by wellhead production, plant recoveries, operating availability of our facilities, physical integrity and our competitive position on a regional basis, and more broadly by demand for natural gas, NGLs and condensate. Historical and current trends in the price changes of commodities may not be indicative of future trends. Throughput and prices are also driven by demand and take-away capacity for residue natural gas and NGLs.

Our processing contract arrangements can have a significant impact on our profitability and cash flow. Our actual contract terms are based upon a variety of factors, including the commodity pricing environment at the time the contract is executed, natural gas quality, geographic location, customer requirements and competition from other midstream service providers. Our gathering and processing contract mix and, accordingly, our exposure to natural gas, NGL and condensate prices, may change as a result of producer preferences, impacting our expansion in regions where certain types of contracts are more common as well as other market factors.

Our Natural Gas Services segment operating results are impacted by market conditions causing variability in natural gas, crude oil and NGL prices. The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by drilling activity, which may be impacted by prevailing commodity prices. The number of active oil and gas drilling rigs in the United States has decreased, from 698 on December 31, 2015 to 563 on December 31, 2016 (Source: IHS). Although the prevailing price of residue natural gas has less short-term significance to our operating results than the price of NGLs, in the long-term, the growth and sustainability of our business depends on commodity prices being at levels sufficient to provide incentives and capital for producers to explore and produce natural gas.

The prices of NGLs, crude oil and natural gas can be extremely volatile for periods of time, and may not always have a close relationship. Due to our hedging program, changes in the relationship of the price of NGLs and crude oil may cause our commodity price exposure to vary, which we have attempted to capture in our commodity price sensitivities in “Quantitative and Qualitative Disclosures about Market Risk.” Our results may also be impacted as a result of non-cash lower of cost or market inventory or imbalance adjustments, which occur when the market value of commodities decline below our carrying value.

The natural gas services business is highly competitive in our markets and includes major integrated oil and gas companies, interstate and intrastate pipelines, and companies that gather, compress, treat, process, transport, store and/or market natural gas. Competition is often the greatest in geographic areas experiencing robust drilling by producers and during periods of high commodity prices for crude oil, natural gas and/or natural gas liquids. Competition is also increased in those geographic areas where our commercial contracts with our customers are shorter in length of term and therefore must be renegotiated on a more frequent basis.

NGL Logistics Segment

Our NGL Logistics segment operating results are impacted by, among other things, the throughput volumes of the NGLs we transport on our NGL pipelines and the volumes of NGLs we fractionate and store. We transport, fractionate and store NGLs primarily on a fee basis. Throughput may be negatively impacted as a result of our customers operating their processing plants in ethane rejection mode, often as a result of low ethane prices relative to natural gas prices. Factors that impact the supply and demand of NGLs, as described above in our Natural Gas Services segment, may also impact the throughput and volume for our NGL Logistics segment.

Wholesale Propane Logistics Segment

Our Wholesale Propane Logistics segment operating results are impacted by our ability to provide our propane distribution customers with reliable supplies of propane. We used physical inventory, physical purchase agreements and financial derivative instruments, with DCP Midstream, LLC or third parties, which typically match the quantities of propane subject to fixed price sales agreements to mitigate our commodity price risk. Our results may also be impacted as a result of non-cash lower of cost or market inventory adjustments, which occur when the market value of propane declines below our carrying value. We generally recover lower of cost or market inventory adjustments in subsequent periods through the sale of inventory, or settlement of financial derivative instruments. There may be positive or negative impacts on sales volumes and gross margin from supply disruptions and weather conditions in the Mid-Atlantic, upper Midwestern and Northeastern areas of the United States. Our annual sales volumes of propane may decline when these areas experience periods of milder weather in the winter months. Volumes may also be impacted by conservation and reduced demand in a recessionary environment. During times of reduced demand domestically, we may export propane.

The wholesale propane business is highly competitive in our market areas which include the Mid-Atlantic, upper Midwest and Northeastern areas of the United States. Our competitors include major integrated oil and gas and energy companies, interstate and intrastate pipelines, as well as marketers and wholesalers.

Weather

The economic impact of severe weather may negatively affect the nation’s short-term energy supply and demand, and may result in commodity price volatility. Additionally, severe weather may restrict or prevent us from fully utilizing our assets, by damaging our assets, interrupting utilities, and through possible NGL and natural gas curtailments downstream of our facilities, which restricts our production. These impacts may linger past the time of the actual weather event. Severe weather may also impact the supply availability and propane demand in our Wholesale Propane Logistics segment. Although we carry insurance on the vast majority of our assets, insurance may be inadequate to cover our loss in some instances, and in certain circumstances we have been unable to obtain insurance on commercially reasonable terms, if at all.

Capital Markets

Volatility in the capital markets may impact our business in multiple ways, including limiting our producers’ ability to finance their drilling programs and operations and limiting our ability to support or fund our operations. These events may impact our counterparties' ability to perform under their credit or commercial obligations. Where possible, we have obtained additional collateral agreements, letters of credit from highly rated banks, or have managed credit lines to mitigate a portion of these risks.

Impact of Inflation

Inflation has been relatively low in the United States in recent years. However, the inflation rates impacting our business fluctuate throughout the broad economic and energy business cycles. Consequently, our costs for chemicals, utilities, materials and supplies, labor and major equipment purchases may increase during periods of general business inflation or periods of relatively high energy commodity prices.

Other

The above factors, including sustained deterioration in commodity prices and volumes, other market declines or a decline in our unit price, may negatively impact our results of operations, and may increase the likelihood of a non-cash impairment charge or non-cash lower of cost or market inventory adjustments.

Recent Events

On December 30, 2016, we entered into a Contribution Agreement with DCP Midstream, LLC and DCP Midstream Operating, LP. The Transaction closed effective January 1, 2017. For additional information regarding the Transaction, see Note 4 of the Notes to Consolidated Financial Statements in Item 8. “Financial Statements and Supplementary Data".

On January 26, 2017, we announced that the board of directors of the General Partner declared a quarterly distribution of $0.78 per unit, payable on February 14, 2017 to unitholders of record on February 7, 2017, except that the owners of the partnership's General Partner will receive distributions on the units issued on January 1, 2017 beginning with the first quarter 2017 declared distribution.

Our Operations

We manage our business and analyze and report our results of operations on a segment basis. Prior to the Transaction, our operations were divided into our Natural Gas Services segment, NGL Logistics segment and Wholesale Propane Logistics segment.

Natural Gas Services Segment

Results of operations from our Natural Gas Services segment are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, transported, stored and sold through our gathering, processing and pipeline systems; the volumes of NGLs and condensate sold; and the level of our realized natural gas, NGL and condensate prices. We generate our revenues and our gross margin for our Natural Gas Services segment principally from contracts that contain a combination of the following arrangements:

- Fee-based arrangements - Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, compressing, treating, processing, transporting or storing natural gas. The revenues we earn are directly related to the volume of natural gas or NGLs that flows through our systems and are not directly dependent on commodity prices. However, to the extent a sustained decline in commodity prices results in a decline in volumes, our revenues from these arrangements would be reduced.

- Percent-of-proceeds/liquids arrangements - Under percent-of-proceeds arrangements, we generally purchase natural gas from producers at the wellhead, or other receipt points, gather the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas, NGLs and condensate based on index prices from published index market prices. We remit to the producers either an agreed-upon percentage of the actual proceeds that we receive from our sales of the residue natural gas, NGLs and condensate, or an agreed-upon percentage of the proceeds based on index related prices for the natural gas, NGLs and condensate, regardless of the actual amount of the sales proceeds we receive. We keep the difference between the proceeds received and the amount remitted back to the producer. Under percent-of-liquids arrangements, we do not keep any amounts related to residue natural gas proceeds and only keep amounts related to the difference between the proceeds received and the amount remitted back to the producer related to NGLs and condensate. Certain of these arrangements may also result in the producer retaining title to all or a portion of the residue natural gas and/or the NGLs, in lieu of us returning sales proceeds to the producer. Additionally, these arrangements may include fee-based components. Our revenues under percent-of-proceeds arrangements relate directly with the price of natural gas, NGLs and condensate. Our revenues under percent-of-liquids arrangements relate directly to the price of NGLs and condensate.

62

In addition to the above contract types, we have keep-whole arrangements, which are estimated to generate an insignificant portion of our gross margin. Discovery, in which we have a 40% interest, also has keep-whole arrangements. Under the terms of a keep-whole processing contract, natural gas is gathered from the producer for processing, the NGLs and condensate are sold and the residue natural gas is returned to the producer with a Btu content equivalent to the Btu content of the natural gas gathered. This arrangement keeps the producer whole to the thermal value of the natural gas received. Under this type of contract, we are exposed to the frac spread. The frac spread is the difference between the value of the NGLs and condensate extracted from processing and the value of the Btu equivalent of the residue natural gas. We benefit in periods when NGL and condensate prices are higher relative to natural gas prices when that frac spread exceeds our operating costs. Fluctuations in commodity prices are expected to continue to impact the operating costs of these entities.

The natural gas supply for our gathering pipelines and processing plants is derived primarily from natural gas wells located in Arkansas, Colorado, Michigan, Oklahoma, Texas, Wyoming and the Gulf of Mexico. We identify primary suppliers as those individually representing 10% or more of our total natural gas supply. We had no supplier of natural gas representing 10% or more of our total natural gas supply during the year ended December 31, 2016. We actively seek new supplies of natural gas, both to offset natural declines in the production from connected wells and to increase throughput volume. We obtain new natural gas supplies in our operating areas by contracting for production from new wells, connecting new wells drilled on dedicated acreage, or by obtaining natural gas that has been directly received or released from other gathering systems.

We sell natural gas to marketing affiliates of natural gas pipelines, integrated oil companies, DCP Midstream, LLC, national wholesale marketers, industrial end-users and gas-fired power plants. We typically sell natural gas under market index related pricing terms. The NGLs extracted from the natural gas at our processing plants are sold at market index prices to DCP Midstream, LLC or its affiliates, or to third parties.

We manage the commodity price risk of our supply portfolio and sales portfolio with both physical and financial transactions. As a service to our customers, we may enter into physical fixed price natural gas purchases and sales, utilizing financial derivatives to swap this fixed price risk back to market index. We manage commodity price risk related to our natural gas storage and pipeline assets through our commodity derivative program. The commercial activities related to our natural gas storage and pipeline assets primarily consist of the purchase and sale of gas and associated time spreads and basis spreads.

A time spread transaction is executed by establishing a long gas position at one point in time and establishing an equal short gas position at a different point in time. Time spread transactions allow us to lock in a margin supported by the injection, withdrawal, and storage capacity of our natural gas storage assets. We may execute basis spread transactions to mitigate the risk of sale and purchase price differentials across our system. A basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas, including injections and withdrawals from storage.

NGL Logistics Segment

Our pipelines, fractionation facilities and storage facility provide transportation, fractionation and storage services for customers, primarily on a fee basis. We have entered into contractual arrangements that generally require customers to pay us to transport or store NGLs pursuant to a fee-based rate that is applied to volumes. These contractual arrangements may require our customers to commit a minimum level of volumes to our pipelines and facilities, thereby mitigating our exposure to volume risk. However, the results of operations for this business segment are generally dependent upon the volume of product transported, fractionated or stored and the level of fees charged to customers. We do not take title to the products transported on our NGL pipelines, fractionated in our fractionation facilities or stored in our storage facility; rather, the customer retains title and the associated commodity price risk. DCP Midstream, LLC provided 100% of volumes transported on the Wattenberg and Seabreeze pipelines. The volumes of NGLs transported on our pipelines are dependent on the level of production of NGLs from processing plants connected to our NGL pipelines. When natural gas prices are high relative to NGL prices, it is less profitable to process natural gas because of the higher value of natural gas compared to the value of NGLs and because of the increased cost of separating the NGLs from the natural gas. As a result, we have experienced periods in the past, in which higher natural gas or lower NGL prices reduce the volume of NGLs extracted at plants connected to our NGL pipelines and, in turn, lower the NGL throughput on our assets. DCP Midstream, LLC, the largest gatherer and processor in the DJ Basin, delivers NGLs to our fractionation facilities under a long-term fractionation agreement. Our storage facility in Marysville, Michigan provides storage and related services primarily to regional refining and petrochemical companies and NGL marketers operating in the liquid hydrocarbons industry.

Wholesale Propane Logistics Segment

We operate a wholesale propane logistics business in the mid-Atlantic, upper Midwest and Northeastern United States. We purchase large volumes of propane supply from natural gas processing plants and fractionation facilities, and crude oil refineries, primarily located in the Texas and Louisiana Gulf Coast area, Canada and other international sources, and transport these volumes of propane supply by pipeline, rail or ship to our terminals and storage facilities in the Mid-Atlantic, Midwest and the Northeastern areas of the United States. We identify primary suppliers as those individually representing 10% or more of our total propane supply. Our two primary suppliers of propane, one of which is an affiliated entity, represented approximately 95% of our propane supplied during the year ended December 31, 2016. We primarily sell propane on a wholesale basis to propane distributors who in turn resell propane to their customers.

Due to our multiple propane supply sources, annual and long-term propane supply purchase arrangements, significant storage capabilities, and multiple terminal locations for wholesale propane delivery, we are generally able to provide our propane distribution customers with reliable supplies of propane during periods of tight supply, such as the winter months when their customers generally consume the most propane for home heating. In particular, we generally offer our customers the ability to obtain propane supply volumes from us in the winter months that are generally significantly greater than their purchases of propane from us in the summer. We believe these factors allow us to maintain our generally favorable relationships with our customers.

We manage our wholesale propane margins by selling propane to propane distributors under annual sales agreements negotiated each spring which specify floating price terms that provide us a margin in excess of our floating index-based supply costs under our supply purchase arrangements. Our portfolio of multiple supply sources and storage capabilities allows us to actively manage our propane supply purchases and to lower the aggregate cost of supplies. Based on the carrying value of our inventory, timing of inventory transactions and the volatility of the market value of propane, we have historically and may continue to periodically recognize non-cash lower of cost or market inventory adjustments. In addition, we may use financial derivatives to manage the value of our propane inventories.

How We Evaluate Our Operations

Our management uses a variety of financial and operational measurements to analyze our performance. These measurements include the following: (1) volumes; (2) gross margin and segment gross margin; (3) operating and maintenance expense, and general and administrative expense; (4) adjusted EBITDA, (5) adjusted segment EBITDA; and (6) Distributable Cash Flow. Gross margin, segment gross margin, adjusted EBITDA, adjusted segment EBITDA, and Distributable Cash Flow are not measures under accounting principles generally accepted in the United States of America, or GAAP. To the extent permitted, we present certain non-GAAP measures and reconciliations of those measures to their most directly comparable financial measures as calculated and presented in accordance with GAAP. These non-GAAP measures may not be comparable to a similarly titled measure of another company because other entities may not calculate these non-GAAP measures in the same manner.

Volumes - We view throughput and storage volumes for our Natural Gas Services segment and our NGL Logistics segment, and sales volumes for our Wholesale Propane Logistics segment as important factors affecting our profitability. We gather and transport some of the natural gas and NGLs under fee-based transportation contracts. Revenue from these contracts is derived by applying the rates stipulated to the volumes transported. Pipeline throughput volumes from existing wells connected to our pipelines will naturally decline over time as wells deplete. Accordingly, to maintain or to increase throughput levels on these pipelines and the utilization rate of our natural gas processing plants, we must continually obtain new supplies of natural gas and NGLs. Our ability to maintain existing supplies of natural gas and NGLs and obtain new supplies are impacted by: (1) the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to our pipelines; and (2) our ability to compete for volumes from successful new wells in other areas. The throughput volumes of NGLs and gas on our pipelines are substantially dependent upon the quantities of NGLs and gas produced at our processing plants, as well as NGLs and gas produced at other processing plants that have pipeline connections with our NGL and gas pipelines. We regularly monitor producer activity in the areas we serve and in which our pipelines are located, and pursue opportunities to connect new supply to these pipelines. We also monitor our inventory in our NGL and gas storage facilities, as well as overall demand for storage based on seasonal patterns and other market factors such as weather and overall demand.

Results of Operations
This section reflects operations of the partnership in 2016, which was prior to the Transaction.

Consolidated Overview
The following table and discussion is a summary of our consolidated results of operations for the years ended December 31, 2016, 2015 and 2014. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Year Ended December 31,			Variance 2016 vs. 2015		Variance 2015 vs. 2014	
	2016	2015	2014 (a)	Increase (Decrease)	Percent	Increase (Decrease)	Percent
	(Millions, except operating data)						
Operating revenues (b):							
Natural Gas Services	$1,269	$1,618	$3,163	$(349)	(22)%	$(1,545)	(49)%
NGL Logistics	85	80	73	5	6 %	$7	10 %
Wholesale Propane Logistics	146	200	406	(54)	(27)%	$(206)	(51)%
Intra-segment eliminations	(3)	—	—	(3)	*	$—	— %
Total operating revenues	1,497	1,898	3,642	(401)	(21)%	$(1,744)	(48)%
Purchases:							
Natural Gas Services	(838)	(1,103)	(2,407)	(265)	(24)%	(1,304)	(54)%
Wholesale Propane Logistics	(111)	(143)	(388)	(32)	(22)%	(245)	(63)%
Intra-segment eliminations	3	—	—	(3)	*	—	— %
Total purchases	(946)	(1,246)	(2,795)	(300)	(24)%	(1,549)	(55)%
Operating and maintenance expense	(183)	(214)	(216)	(31)	(14)%	(2)	(1)%
Depreciation and amortization expense	(122)	(120)	(110)	2	2 %	10	9 %
General and administrative expense	(88)	(85)	(64)	3	4 %	21	33 %
Goodwill impairment	—	(82)	—	(82)	*	82	*
Other expense	(7)	(4)	(3)	3	75 %	1	33 %
Earnings from unconsolidated affiliates (c)	214	173	75	41	24 %	98	131 %
Interest expense	(94)	(92)	(86)	2	2 %	6	7 %
Income tax benefit (expense)	—	5	(6)	(5)	*	11	*
Gain on sale of assets	47	—	—	47	*	—	— %
Net income attributable to noncontrolling interests	(6)	(5)	(14)	1	20 %	(9)	(64)%
Net income attributable to partners	$312	$228	$423	$84	37 %	$(195)	(46)%
Other data:							
Gross margin (d):							
Natural Gas Services	$431	$515	$756	$(84)	(16)%	$(241)	(32)%
NGL Logistics	85	80	$73	$5	6 %	$7	10 %
Wholesale Propane Logistics	35	57	$18	$(22)	(39)%	$39	217 %
Total gross margin	$551	$652	$847	$(101)	(15)%	$(195)	(23)%
Non-cash commodity derivative mark-to-market	$(108)	$(130)	$86	$(22)	(17)%	$(216)	*
Natural gas throughput (MMcf/d) (e)	2,449	2,714	2,604	(265)	(10)%	110	4 %
NGL gross production (Bbls/d) (e)	154,959	161,007	157,722	(6,048)	(4)%	3,285	2 %
NGL pipelines throughput (Bbls/d) (e)	289,395	261,659	184,706	27,736	11 %	76,953	42 %
NGL fractionator throughput (Bbls/d) (e)	60,296	56,927	61,509	3,369	6 %	(4,582)	(7)%
Propane sales volume (Bbls/d)	13,309	15,685	18,335	(2,376)	(15)%	(2,650)	(14)%

* Percentage change is not meaningful.

(a) Includes the results of our Lucerne 1 plant, retrospectively adjusted, which we acquired on March 28, 2014.
(b) Operating revenues include the impact of commodity derivative activity.
(c) Earnings for Discovery, Sand Hills, Southern Hills, Front Range, Mont Belvieu 1 and Texas Express include the amortization of the net difference between the carrying amount of the investments and the underlying equity of the entities.
(d) Gross margin consists of total operating revenues, including commodity derivative activity, less purchases of natural gas, propane and NGLs. Segment gross margin for each segment consists of total operating revenues for that segment, including commodity derivative activity, less commodity purchases for that segment. Please read "Reconciliation of Non-GAAP Measures".
(e) For entities not wholly-owned by us, includes our share, based on our ownership percentage, of the throughput volumes and NGL production.

Year ended December 31, 2016 vs. Year ended December 31, 2015

Total Operating Revenues — Total operating revenues decreased $401 million in 2016 compared to 2015 primarily as a result of the following:

- $349 million decrease for our Natural Gas Services segment primarily due to decreased commodity prices, lower gas and NGL sales volumes primarily related to our Eagle Ford and East Texas systems which impact both sales and purchases, lower prices and volumes at our natural gas storage and pipeline assets, unfavorable commodity derivative activity and the disposition of our Northern Louisiana system, partially offset by growth in our DJ Basin system; and
- $54 million decrease for our Wholesale Propane Logistics segment primarily due to lower propane volumes and prices.

Total Purchases — Total purchases decreased $300 million in 2016 compared to 2015 primarily as a result of the following:

- Purchases of natural gas and NGLs decreased $265 million in 2016 compared to 2015 as a result of decreased commodity prices and lower gas and NGL sales volumes, primarily related to our Eagle Ford and East Texas systems, and decreased volumes at our natural gas storage and pipeline assets, which impact both sales and purchases; and
- Purchases of propane decreased in 2016 compared to 2015 primarily due to decreased volumes as discussed below under the heading "Propane Sales Volumes" and lower propane prices which impact both sales and purchases.

Operating and Maintenance Expense — Operating and maintenance expense decreased in 2016 compared to 2015 primarily as a result of improved operating efficiencies, other cost savings initiatives, and the disposition of our Northern Louisiana system.

Goodwill impairment— Goodwill impairment expense in 2015 represents impairment of our Collbran, Michigan and Southeast Texas reporting units.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2016 compared to 2015 primarily as a result of the completion of the Keathley Canyon project at Discovery in February 2015 in our Natural Gas Services segment and increased volumes on our Sand Hil