DCP Midstream, LP
Form 10-K
February 26, 2018
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, 2017
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. Yesý No¨
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No 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. Yesý No¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of regulation S-T (§232.405

of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨
Indicate by check mark 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, a smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act. (Check one):

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

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

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

The aggregate market value of common units held by non-affiliates of the registrant on June 30, 2017, was approximately $3,060,364,000. 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, 2017.

As of February 22, 2018, there were 143,309,828 common units representing limited partner interests outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:
None.

DCP MIDSTREAM, LP
FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2017
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;
- general economic, market and business conditions;
- our ability to continue the safe and reliable operation of our assets;
- 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;
- 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;
- 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 grow through organic growth projects, or acquisitions, and the successful integration and future performance of such assets;
- our ability to hire, train, and retain qualified personnel and key management to execute our business strategy;
- 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;
- 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 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

Item 1. Business

OVERVIEW

DCP Midstream, LP (together with its consolidated subsidiaries, “we”, “our”, “us”, the “registrant”, or the “Partnership”) is 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. DCP Midstream, LLC and its subsidiaries and affiliates, collectively referred to as DCP Midstream, LLC is owned 50% by Phillips 66 and 50% by Enbridge Inc. and its affiliates, or Enbridge.

The diagram below depicts our organizational structure as of December 31, 2017.

Our operations are organized into two reportable segments: (i) Gathering and Processing and (ii) Logistics and Marketing. Our Gathering and Processing segment consists of gathering, compressing, treating, and processing natural gas, producing and fractionating NGLs, and recovering condensate. Our Logistics and Marketing segment includes transporting, trading, marketing, and storing natural gas and NGLs, fractionating NGLs, and wholesale propane logistics. The remainder of our business operations are presented as “Other,” and consist of unallocated corporate costs.

OUR BUSINESS STRATEGY

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

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. Our gathering and processing systems and logistics assets consist of high-quality, well-maintained facilities, resulting in low-cost, efficient operations. Our goal is to establish a reputation in the midstream industry as a reliable, safe and low cost supplier of services to our customers. We will continue to pursue new contracts, cost efficiencies and operating improvements of our assets through process and technology improvements. We seek to increase the utilization of our existing facilities by providing additional services to our existing customers and by establishing relationships with new customers. In addition, we maximize efficiency by coordinating the completion of new facilities in a manner that is consistent with the expected production that supports them.

Organic 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 one of the largest producers and marketers of NGLs in the United States, as a platform for future growth. We plan to grow our business by constructing new NGL and natural gas pipeline infrastructure, expanding existing infrastructure, and constructing new gathering lines and processing facilities.

Strategic Partnerships and Acquisitions. We intend to pursue economically attractive and strategic partnership and acquisition opportunities within the midstream energy industry, both in new and existing lines of business, and areas of operation.

OUR COMPETITIVE STRENGTHS

We are one of the largest gatherers of natural gas and one of the largest producers and marketers of NGLs in the United States. In 2017, our total wellhead volume was approximately 4.5 Bcf/d of natural gas and we produced an average of approximately 375 MBbls/d of NGLs. We provide natural gas gathering services to the wellhead, and leverage our strategic footprint to extend the value chain through our integrated NGL and natural gas pipelines and marketing infrastructure. 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 to move natural gas and NGLs from wellhead to market and creates value for our customers. 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 wellhead volumes and cash flow generation. We have operations in some of the largest producing regions in the United States: Denver-Julesburg Basin (“DJ Basin”), Permian Basin, Midcontinent, and Eagle Ford. In addition, we operate one of the largest portfolios of natural gas processing plants in the United States. Our gathering systems and processing plants are connected to numerous key natural gas pipeline systems that provide producers with access to a variety of natural gas market hubs.

Integrated Logistics and Marketing Operations. 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 to our gathering and processing operations. We have connected our gathering and processing operations to key markets with NGL pipelines that we own or operate to offer our customers a competitive, integrated midstream service. We have strategically located NGL transportation pipelines that provide takeaway capabilities for our gathering and processing operations in the Permian Basin, DJ Basin, Midcontinent, East Texas, Gulf Coast, South Texas, and Central Texas. 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 Logistics and Marketing operations also consists of multiple downstream assets including NGL fractionation facilities, an NGL storage facility and a residue gas storage facility.

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. 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 2019.

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 Enbridge, 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, an approximately 36% limited partner interest and all of our incentive distribution rights.

OUR OPERATING SEGMENTS

Gathering and Processing Segment

General

Our Gathering and Processing 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 in Alabama, Colorado, Kansas, Louisiana, Michigan, New Mexico, Oklahoma, Texas and Wyoming. These services include gathering, compressing, treating, and processing natural gas, producing and fractionating NGLs, and recovering condensate. Our Gathering and Processing segment's operations are organized into four regions: North, Permian, Midcontinent and South. Our 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 is an important factor for maintaining and growing overall volumes and cash flow for this segment. Our assets are positioned in certain areas with active drilling programs and opportunities for organic growth.
We provide our producer customers with gathering and processing services that allow them to move their raw (unprocessed) natural gas to market. Raw natural gas is gathered, compressed and transported through pipelines to our processing facilities. In order for the raw natural gas to be accepted by the downstream market, we remove water, nitrogen and carbon dioxide and separate NGLs for further processing. Processed natural gas, usually referred to as residue natural gas, is then recompressed and delivered to natural gas pipelines and end users. The separated NGLs are in a mixed, unfractionated form and are sold and delivered through natural gas liquids pipelines to fractionation facilities for further separation.
We own or operate 61 natural gas processing plants and an interest in one additional plant through our 40% equity interest in Discovery Producer Services, LLC, or Discovery. At some of these facilities, we fractionate NGLs into individual components (ethane, propane, butane and natural gasoline).
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. 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 fee-based or percent-of-proceeds/index processing contracts.
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 Gathering and Processing segment are a mix of non-commodity sensitive fee-based contracts and commodity sensitive percent-of-proceeds and percent-of-liquids contracts. Percent-of-proceeds contracts are directly related to the price of natural gas, NGLs and condensate and percent-of-liquids contracts are 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 three to five years and 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.

We enter into derivative financial instruments to mitigate a portion of the risk of weakening natural gas, NGL and condensate prices associated with our gathering, processing and sales activities, thereby stabilizing our cash flows. Our commodity derivative instruments used for our hedging program are a combination of direct NGL product, crude oil, and natural gas hedges.

During 2017, total wellhead volume on our assets was approximately 4.5 Bcf/d, originating from a diversified mix of customers. Our systems each have significant customer acreage dedications that we expect 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 2017, the combined NGL production from our processing facilities was approximately 375 MBbls/d and was delivered and sold into various NGL takeaway pipelines.

The following is operating data for our Gathering and Processing segment by region:

Operating Data

				Year Ended December 31, 2017	
Regions	Plants	Approximate Gathering and Transmission Systems (Miles)	Approximate Net Nameplate Plant Capacity (MMcf/d) (a)	Natural Gas Wellhead Volume (MMcf/d) (a)	NGL Production (MBbls/d) (a)
North	13	4,000	1,260	1,121	86
Permian	16	16,500	1,460	941	103
Midcontinent	12	29,000	1,765	1,229	94
South	20	7,500	3,295	1,240	92
Total	61	57,000	7,780	4,531	375

(a) Represents total capacity or total volumes allocated to our proportionate ownership share.

North Region

Our North region primarily consists of our DJ Basin system. We have a broad network of gathering and processing facilities in Weld County, Colorado that provide significant optionality and flexibility.
We are constructing a new 200 MMcf/d cryogenic natural gas processing plant, Mewbourn 3, and further expanding our Grand Parkway gathering system, both of which are expected to be placed in service in the third quarter of 2018. Our Mewbourn 3 plant will increase capacity to support the growing processing needs of producers in the DJ Basin.
Our 200 MMcf/d O'Connor 2 plant and associated gathering infrastructure is progressing and expected to be in service in 2019.
Our DJ Basin system delivers to the Mont Belvieu hub in Mont Belvieu, Texas via the Front Range and Texas Express pipelines, owned 33.33% and 10% by us, respectively, and to the Conway hub in Bushton, Kansas via our Wattenberg pipeline in our Logistics and Marketing segment.

Permian Region
Our Permian region primarily includes our West Texas system in the Midland Basin and our Southeast New Mexico system in the Delaware Basin. Producers continue to focus drilling activity on the most attractive acreage in the Midland and Delaware Basins. Our gathering and processing assets in the Permian region provide NGL takeaway service via our Sand Hills pipeline, which is owned 66.67% by us and 33.33% by Phillips 66, to fractionation facilities along the Gulf Coast and to the Mont Belvieu hub.

Midcontinent Region

Our Midcontinent region primarily includes our Liberal system, Panhandle system, and our South Central Oklahoma system. We gather and process raw natural gas primarily from the Ardmore and Anadarko Basins, including the South Central Oklahoma Oil Province (“SCOOP”) play and the Sooner Trend Anadarko Basin Canadian and Kingfisher (“STACK”) play.

Existing production in the western Midcontinent region, which includes our Liberal and Panhandle systems, is typically from mature fields with shallow decline profiles that we expect will provide our plants with a dependable source of raw natural gas over a long term. We believe the infrastructure of our plants and gathering facilities is uniquely positioned to pursue our consolidation strategy in the western Midcontinent region. Our gathering system footprint in the eastern Midcontinent region, which includes our South Central Oklahoma system, serves the SCOOP and STACK plays.

Our gathering and processing assets in the Midcontinent region deliver NGLs primarily to the Gulf Coast and Mont Belvieu via our Southern Hills pipeline, owned 66.67% by us and 33.33% by Phillips 66.

South Region

Our South region primarily includes our Eagle Ford system, East Texas system, and our 40% interest in the Discovery system. We are pursuing cost efficiencies and increasing the utilization of our existing assets.

Our Eagle Ford system delivers NGLs to the Gulf Coast petrochemical markets and to Mont Belvieu through our Sand Hills pipeline and other third party NGL pipelines. Our East Texas system provides NGL takeaway service through the Panola pipeline, owned 15% by us, and delivers gas primarily through its Carthage Hub which delivers residue gas to multiple interstate and intrastate pipelines.

The Discovery system is operated by Williams Partners L.P., which owns a 60% interest, 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 Louisiana, and have access to downstream pipelines and markets.

Competition

We face strong competition in acquiring raw natural gas supplies. Our competitors in obtaining additional gas supplies and in gathering and processing raw natural gas 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.

Logistics and Marketing Segment

General

We market our NGLs, residue gas and condensate and provide logistics and marketing services to third-party NGL producers and sales customers in significant NGL production and market centers in the United States. This includes purchasing NGLs on behalf of third-party NGL producers for shipment on our NGL pipelines and resale in key markets.

Our NGL services include plant tailgate purchases, transportation, fractionation, flexible pricing options, price risk management and product-in-kind agreements. Our primary NGL operations are located in close proximity to our Gathering and Processing assets in each of the operating 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 natural gas systems have the ability to deliver gas into numerous downstream transportation pipelines and markets. We sell residue gas on behalf of our producer customers and residue gas which we earn under our gas supply agreements, supplying the residue gas demands of end-use customers physically attached to our pipeline systems and managing excess capacity of our owned storage and transportation assets. End-users include large industrial companies, natural gas distribution companies and electric utilities. We are focused on extracting the highest possible value for the residue gas that results from our processing and transportation operations. We sell the residue gas at market-based prices.

Our ownership in various intrastate natural gas pipelines give us access to market centers/hubs such as Waha, Texas; Katy, Texas and the Houston Ship Channel and are used in our natural gas asset based trading activities.
The following is operating data for our Logistics and Marketing segment:
Operating Data

System	Approximate System Length (Miles)	Fractionators	Approximate Throughput Capacity (MBbls/d) (a)	Approximate NGL Storage Capacity (MMBbls)	Approximate Natural Gas Storage Capacity (Bcf)	Year Ended December 31, 2017 Pipeline Throughput (MBbls/d) (a)	Year Ended December 31, 2017 Fractionator Throughput (MBbls/d) (a)
Sand Hills pipeline	1,300	—	227	—	—	192	—
Southern Hills pipeline	950	—	117	—	—	69	—
Front Range pipeline	455	—	50	—	—	36	—
Texas Express pipeline	595	—	28	—	—	15	—
Other pipelines	1,200	—	241	—	—	148	—
Mont Belvieu fractionators	—	2	60	—	—	—	48
Storage facilities	—	—	—	8	12	—	—
Total	4,500	2	722	8	12	460	48

(a) Represents total NGL capacity or throughput allocated to our proportionate ownership share for 2017 divided by 365 days.

NGL Pipelines

DCP Sand Hills Pipeline, LLC, or the Sand Hills pipeline, an interstate NGL pipeline in which we own a 66.67% interest, 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. We have completed the expansion of the Sand Hills pipeline to 365 MBbls/d in the first quarter of 2018. Further Sand Hills pipeline expansion to 450 MBbls/d is progressing and includes a partial looping of the pipeline and the addition of new pump stations, and is expected to be in service in the second half of 2018.
DCP Southern Hills Pipeline, LLC, or the Southern Hills pipeline, an interstate NGL pipeline in which we own a 66.67% interest, provides takeaway service from the Midcontinent to fractionation facilities at the Mont Belvieu, Texas market hub.
Front Range Pipeline LLC, or the Front Range pipeline, an interstate NGL pipeline in which we own a 33.33% interest, originates in the DJ Basin and extends to Skellytown, Texas. The Front Range pipeline connects to our O'Connor, Lucerne 1, Lucerne 2, and Mewbourn plants as well as third party plants in the DJ Basin. Enterprise Products Partners L.P., or Enterprise, is the operator of the pipeline.
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's 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 Southern Hills, Sand Hills, Texas Express, and Front Range pipelines have in place long-term, fee-based transportation agreements, a portion of which are ship-or-pay, with us as well as third party shippers. These NGL pipelines collect fee-based transportation revenue under regulated tariffs.

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. The fractionation facilities separate NGLs received from processing plants into their individual components. These fractionation services are provided on a fee basis. The

results of operations for this business are generally dependent upon the volume of NGLs fractionated and the level of fees charged to customers.

Storage Facilities

Our NGL storage facility, which stores ethane, propane and butane, is located in Marysville, Michigan and has strategic access to the Marcellus, Utica and Canadian NGLs. Our facility includes 11 underground salt caverns with approximately 8 MMBbls of storage capacity. 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 under multi-year storage agreements. The results of operations for this business are generally dependent upon the volume stored and the level of fees charged to customers.

Our Spindletop natural gas storage facility is located in Texas and plays an important role in our ability to act as a full-service natural gas marketer. The facility has capacity for residue gas of approximately 12 Bcf. We may lease a portion of the facility's capacity to third-party customers, and use the balance to manage relatively constant natural gas supply volumes with uneven demand levels, provide "backup" service to our customers and support our asset based trading activities. Our asset based trading activities are designed to realize margins related to fluctuations in commodity prices, time spreads and basis differentials and to maximize the value of our storage facility.

Wholesale Propane

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 fractionation facilities and crude oil refineries, primarily located in the Marcellus/Utica area, Canada and other international sources, and transport these volumes of propane supply by pipeline, rail or ship to our terminals and storage facilities. We primarily sell propane on a wholesale basis to propane distributors under annual sales agreements who in turn resell propane to their customers. Our operations include one owned marine terminal, five owned propane rail terminals and one joint venture rail terminal, with access to several open access pipeline terminals.

The wholesale propane marketing business is significantly impacted by seasonal and weather-driven demand, particularly in the winter, which can impact the price and volume of propane sold in the markets we serve.

Trading and Marketing

Our energy trading operations are exposed to market variables and commodity price risk. We manage commodity price risk related to our natural gas storage and pipeline assets by engaging in natural gas asset based trading and marketing. We 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.

Our NGL proprietary trading activity includes trading energy related products and services. We undertake these activities 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.

We may execute a time spread transaction when the difference between the current price of natural gas (cash or futures) and the futures market price for natural gas exceeds our cost of storing physical gas in our owned and/or leased storage facilities. The time spread transaction allows us to lock in a margin when this market condition exists. 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.

We may execute basis spread transactions when the market price differential between locations on a pipeline asset exceeds our cost of transporting physical gas through our owned and/or leased pipeline asset. When this market condition exists, we may execute derivative instruments around this differential at the market price. This basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas.

Customers and Contracts

We sell our commodities 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 22% of our NGL production which was committed to Phillips 66 and Chevron

Phillips Chemical, or CPChem as of December 31, 2017. The primary production commitment on certain contracts 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.

Competition

The Logistics and Marketing 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 natural gas and 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.

Competition in the NGLs marketing area comes from other midstream NGL marketing companies, international producers/traders, chemical companies, refineries and other asset owners. Along with numerous marketing competitors, we offer price risk management and other services. We believe it is important that we tailor our services to the end-use customer to remain competitive.

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 21 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

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 approximately $47 million between 2018 and 2022 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 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 holding or handling these materials in quantities 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. 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.

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

13

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 common carrier 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. 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 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. The ceiling levels calculated for our interstate NGL pipelines are typically increased each year pursuant to the indexing methodology, but may be subject to decrease, which occurred in 2016 and resulted in the decrease in the tariff rates for many such pipelines.

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:

- requiring the acquisition of permits or authorizations to conduct regulated activities and imposing obligations in those permits, potentially including capital expenditures or operational requirements, that reduce or limit impacts to the environment;
- restricting the ways that 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, potential citizen lawsuits, 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 overall trend in federal and state environmental programs is to expand regulatory requirements, 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, including the Prevention of Significant Deterioration (“PSD”) program and Title V permitting. In 2016 EPA proposed a rule to revise the PSD and Title V permitting regulations applicable to GHGs in response to a 2014 U.S. Supreme Court decision and subsequent D.C. Circuit decision striking down its 2011 rules. The proposed revisions required that major sources of non-GHG 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 equivalent), obtain permits addressing emissions of greenhouse gases. The EPA has not acted to finalize this proposed rule. The EPA also has 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 (“NSPS”) 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 for the first time. In June 2017, EPA published a proposed rule to stay certain requirements of the 2016 NSPS rule for two years while it completes reconsideration of certain aspects of the rule and reviews the entire rule. 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. At EPA’s request, the judicial challenge to the ozone standard in the D.C. Circuit was put in abeyance while EPA reviews the standard. The EPA has also indicated that it will request comments on entirely withdrawing the October 2016 Control Techniques Guidelines for emissions of volatile organic compounds from oil and gas sector sources that were 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 that 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 also 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. As of December 31, 2017, 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" in this Annual Report on Form 10-K.
General
We make certain filings with the Securities and Exchange Commission ("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. Our website and the information contained on that site, or connected to that site, are not incorporated by reference into this report. 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
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 2017, as illustrated by the following table:

	Year Ended December 31, 2017	December 31, 2017

	Daily High	Daily Low	
Commodity:			
NYMEX Natural Gas ($/MMBtu)	$3.42	$2.56	$ 2.95
NGLs ($/Gallon)	$0.76	$0.50	$ 0.76
Crude Oil ($/Bbl)	$60.42	$42.53	$ 60.42

19

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 and importing 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. 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 sheet 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.

Our derivative instruments may require us to post collateral based on predetermined collateral thresholds. Depending on the movement in commodity prices, the amount of posted collateral required 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 supply during the year ended December 31, 2017. 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 Credit Agreement increased. The further lowering of our credit rating could further increase our cost of borrowing under our 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 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 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 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 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 Credit Agreement contains covenants requiring us to maintain a certain leverage ratio and certain other tests. Any subsequent replacement of our 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 2.70% 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 of 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, 2017, 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, 2017, our consolidated principal indebtedness was $4,725 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 and distributions on our units.

Debt service obligations and restrictive covenants in our 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 CFTC has sought comment on the position limits rules as reproposed, but since these 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 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 ("Partnership Agreement"), to our common 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 Credit Agreement is dependent on the ability of the lenders that are party to the 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 Credit Agreement were to fail to fund their share of the Credit Agreement, our available borrowings could be further reduced. In addition, our borrowing capacity may be further limited by the 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 approximately $47 million between 2018 and 2022 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 potential for adverse impacts to our business is present where local governments have enacted ordinances directly regulating pipeline assets and operations, and and private individuals have sponsored 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, 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 the general focus of debate is on upstream development activities, certain proposals may, if adopted, directly impact our ability to competitively locate, construct, maintain, and operate our own assets. 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.

Moreover, in the NOI proceeding, parties have requested that FERC adjust the rates for interstate pipeline services based on the reduction in the federal income tax rates for corporations, as well as partners and other owners of pass-through entities, in the recently enacted Law to Provide for Reconciliation Pursuant to Titles II and V of the Concurrent Resolution on the Budget for Fiscal Year 2018. While we believe there is considerable regulatory precedent and laws that afford pipelines due process rights if their rates are contested, FERC has not yet responded to the motions and we cannot predict the outcome. Any action by FERC could impact the rates for our regulated interstate pipeline services. Additionally, the reduction in the federal income tax rates for corporations and individuals could impact the income tax allowance included in the cost-of-service calculations in future rate proceedings for our regulated interstate pipeline services.

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 June 2016, the EPA expanded the NSPS regulations for new or modified sources of VOCs to include methane emissions. Among other things, this regulation imposes 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 is 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. This regulation is also the subject of review pursuant to the March 28, 2017, Presidential Executive Order on Promoting Energy Independence and Economic Growth, which ordered the EPA Administrator to review this regulation for consistency with the Executive Order's policy to review existing regulations impacting natural gas development and, if appropriate, "suspend, revise, or rescind the guidance or publish for notice and comment proposed rules suspending, revising or rescinding those rules." In response to the Executive Order, in June 2017, EPA published a proposed rule to stay the compliance requirements of the regulation while it reviews the rule. The EPA separately withdrew the information request that it had issued in November 2016 as part of an effort to develop standards for methane and other emissions from existing sources in the oil and natural gas industry. The EPA, in October 2015, 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, such as 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) and additional control requirements. In October 2016, the EPA also finalized Control Techniques Guidelines for VOC emissions from existing oil and natural gas equipment and processes in moderate ozone non-attainment areas. These Control Techniques Guidelines provide recommendations for states and local air agencies to consider when determining what emissions control requirements apply to sources in the non-attainment areas. In late 2017, however, EPA indicated that it will request comments on withdrawing the guidelines in their entirety. Collectively, these regulations could require modifications to the operations of our 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 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. In August 2017, however, the U.S. notified the United Nations Secretary-General that it intends to withdraw from the agreement as soon as it is able to do so, or November 2019. Legislative 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. For example, 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, President Obama announced a climate action plan that targets methane emissions from the oil and gas industry as part of a comprehensive interagency methane reduction strategy. Many of the actions taken under the Obama Administration have been targeted by the Trump Administration. For instance, in June 2017 EPA proposed a two-year stay of the compliance requirements for the new source performance standards for methane emissions (a greenhouse gas) from new and modified oil and gas industry sources that EPA has finalized in 2016. The EPA also indicated that it will request comments on entirely withdrawing the October 2016 Control Techniques Guidelines for emissions of VOCs from existing oil and gas industry sources in ozone nonattainment areas, which had an expected co-benefit of reduced methane emissions. Relatedly, the D.C. Circuit Court challenge to the October 2015 EPA regulation reducing the ambient ozone standard from 75 parts per billion to 70 parts per billion under the Clean Air Act was put in abeyance while the EPA reviews the regulation. Separately, 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. These proposed rules have not been finalized. The EPA 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 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 gas development. The implementation of rules relating to hydraulic fracturing could result in increased expenditures for our exploration and production customers, which could cause them to reduce their production and thereby result in reduced demand for our services by these customers.

On March 28, 2017, President Trump issued Executive Order 13783 entitled “Promoting Energy Independence and Economic Growth.” Executive Order 13783 directed executive departments and agencies to review regulations that potentially burden the development or use of domestically produced energy resources and, as appropriate, suspend, revise, or rescind those that unduly burden domestic energy resources development. On March 26, 2015, the federal Bureau of Land Management (“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. The rule was never implemented due to court challenges. On December 29, 2017, the BLM rescinded the rule. 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, on December 8, 2017, the BLM finalized a rule suspending or delaying many of the provisions of the regulation while it reviews the regulation. Our customers will continue to be subject to uncertainty associated with new regulatory suspensions, revisions, or rescissions and conflicting state and federal regulatory mandates, which could adversely affect 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, legal, and economic uncertainties beyond our control and may require the expenditure of significant amounts of capital. For example, public participation in review and permitting processes can introduce uncertainty and additional costs associated with project timing and completion. Relatedly, 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. 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;
-