Shell Midstream Partners, L.P.
Form 10-K
February 21, 2019
Shell Midstream Partners, L.P.SHLX12/31Large Accelerated
Filer10-K12/31/20182018FYFALSEFALSEFALSEFALSE—YesNoYes2,7440001610466123,832,23398832233123,832,2339

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2018
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: 001-36710

Shell Midstream Partners, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**46-5223743**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

150 N. Dairy Ashford, Houston, Texas 77079
(Address of principal executive offices) (Zip Code)
Registrant’s telephone number, including area code: (832) 337-2034
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 Act. x Yes ¨ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ¨ Yes x No

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).
x Yes ¨ 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 the 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. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company” and “emerging growth company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer	x	Accelerated filer	¨
Non-accelerated filer	¨	Smaller reporting company	¨
Emerging growth company	o		

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. o

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

The aggregate market value of the registrant’s common units held by non-affiliates of the registrant as of June 29, 2018, was $2,744 million, based on the closing price of such units of $22.18 as reported on the New York Stock Exchange on such date. The registrant had 223,811,781 common units and no subordinated units outstanding as of February 21, 2019.

Documents incorporated by reference:

None

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This report includes forward-looking statements. You can identify our forward-looking statements by the words "anticipate," "estimate," "believe," "budget," "continue," "could," "intend," "may," "plan," "potential," "predict," "seek," "sho "objective," "projection," "forecast," "goal," "guidance," "outlook," "effort," "target" and similar expressions.

We based the forward-looking statements on our current expectations, estimates and projections about us and the industries in which we operate in general. We caution you these statements are not guarantees of future performance as they involve assumptions that, while made in good faith, may prove to be incorrect, and involve risks and uncertainties we cannot predict. In addition, we based many of these forward-looking statements on assumptions about future events that may prove to be inaccurate. Accordingly, our actual outcomes and results may differ materially from what we have expressed in the forward-looking statements. Any differences could result from a variety of factors, including the following:

•The continued ability of Royal Dutch Shell plc and our non-affiliate customers to satisfy their obligations under our commercial and other agreements and the impact of lower market prices for crude oil, refined petroleum products and refinery gas.
•The volume of crude oil, refined petroleum products and refinery gas we transport or store and the prices that we can charge our customers.
•The tariff rates with respect to volumes that we transport through our regulated assets, which rates are subject to review and possible adjustment imposed by federal and state regulators.
•Changes in revenue we realize under the loss allowance provisions of our fees and tariffs resulting from changes in underlying commodity prices.
•Our ability to renew or replace our third-party contract portfolio on comparable terms.
•Fluctuations in the prices for crude oil, refined petroleum products and refinery gas.
•The level of production of refinery gas by refineries and demand by chemical sites.
•The level of onshore and offshore (including deepwater) production and demand for crude oil by U.S. refiners.
•Changes in global economic conditions and the effects of a global economic downturn on the business of Shell and the business of its suppliers, customers, business partners and credit lenders.
•Availability of acquisitions and financing for acquisitions on our expected timing and acceptable terms.
•Changes in, and availability to us, of the equity and debt capital markets.
•Liabilities associated with the risks and operational hazards inherent in transporting and/or storing crude oil, refined petroleum products and refinery gas.
•Curtailment of operations or expansion projects due to unexpected leaks, spills, or severe weather disruption; riots, strikes, lockouts or other industrial disturbances; or failure of information technology systems due to various causes, including unauthorized access or attack.
•Costs or liabilities associated with federal, state and local laws and regulations relating to environmental protection and safety, including spills, releases and pipeline integrity.
•Costs associated with compliance with evolving environmental laws and regulations on climate change.
•Costs associated with compliance with safety regulations and system maintenance programs, including pipeline integrity management program testing and related repairs.
•Changes in tax status or applicable tax laws.
•Changes in the cost or availability of third-party vessels, pipelines, rail cars and other means of delivering and transporting crude oil, refined petroleum products and refinery gas.
•Direct or indirect effects on our business resulting from actual or threatened terrorist incidents or acts of war.
•The factors generally described in *Part I, Item 1A. Risk Factors* of this report.

GLOSSARY OF TERMS

Barrel or bbl: One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to crude oil or other liquid hydrocarbons.
BOEM: Bureau of Ocean Energy Management.
BSEE: Bureau of Safety and Environmental Enforcement.
Capacity: Nameplate capacity.
Common carrier pipeline: A pipeline engaged in the transportation of crude oil, refined products or natural gas liquids as a common carrier for hire.
Crude oil: A mixture of raw hydrocarbons that exists in liquid phase in underground reservoirs.
DOT: Department of Transportation.
EPAct: Energy Policy Act of 1992.
Expansion capital expenditures: Expansion capital expenditures is a defined term under our partnership agreement. Expansion capital expenditures are cash expenditures (including transaction expenses) for capital improvements. Expansion capital expenditures do not include maintenance capital expenditures or investment capital expenditures. Expansion capital expenditures do include interest payments (including periodic net payments under related interest rate swap agreements) and related fees paid during the construction period on construction debt. Where cash expenditures are made in part for expansion capital expenditures and in part for other purposes, the general partner determines the allocation between the amounts paid for each.
FERC: Federal Energy Regulatory Commission.
GAAP: United States generally accepted accounting principles.
HCAs: High Consequence Areas.
ICA: Interstate Commerce Act of 1887, as modified by the Elkins Act.
kbpd: Thousand barrels per day.
kbls: Thousand barrels.
klbs/d: Thousand pounds per day.
Life-of-lease transportation agreement: A contract in which the producer dedicates shipments of all current and future reserves pertaining to a specific lease or area to a specific carrier.
LNG: Liquefied natural gas.
LTIP: Shell Midstream Partners, L.P. 2014 Incentive Compensation Plan.
Maintenance capital expenditures: Maintenance capital expenditures is a defined term under our Partnership Agreement. Maintenance capital expenditures are cash expenditures (including expenditures for (a) the acquisition (through an asset acquisition, merger, stock acquisition, equity acquisition or other form of investment) by the Partnership or any of its subsidiaries of existing assets or assets under construction, (b) the construction or development of new capital assets by the Partnership or any of its subsidiaries, (c) the replacement, improvement or expansion of existing capital assets by the Partnership or any of its subsidiaries or (d) a capital contribution by the Partnership or any of its subsidiaries to a person that is not a subsidiary in which the Partnership or any of its subsidiaries has, or after such capital contribution will have, directly or indirectly, an equity interest, to fund the Partnership or such subsidiary's share of the cost of the acquisition, construction or development of new, or the replacement, improvement or expansion of existing, capital assets by such person), in each case if and to the extent such acquisition, construction, development, replacement, improvement or expansion is made to maintain, over the long-term, the operating capacity or operating income of the Partnership and its subsidiaries, in the case of clauses (a), (b) and (c), or such person, in the case of clause (d), as the operating capacity or operating income of the Partnership and its subsidiaries or such person, as the case may be, existed immediately prior to such acquisition, construction, development,

replacement, improvement, expansion or capital contribution. For purposes of this definition, “long-term” generally refers to a period of not less than twelve months.
mscf/d: Million standard cubic feet per day.
Partnership Agreement: First Amended and Restated Agreement of Limited Partnership of Shell Midstream Partners, L.P., dated as of November 3, 2014, as amended by Amendment No. 1 thereto, dated February 26, 2018, and as amended by Amendment No. 2 thereto dated December 21, 2018.
PHMSA: Pipeline and Hazardous Materials Safety Administration.
Pipeline loss allowance or PLA: An allowance for volume losses due to measurement difference set forth in crude oil product transportation agreements, including long-term transportation agreements and tariffs for crude oil shipments.
Refined products: Hydrocarbon compounds, such as gasoline, diesel fuel, jet fuel and residual fuel that are produced by a refinery.
Refinery gas: Non-condensable gas obtained during distillation of crude oil or treatment of oil products in refineries.
Ship-or-pay contract: A contract requiring payment for the transportation of crude oil or refined products even if the crude oil or refined products are not transported.
Throughput: The volume of crude oil, refined products or natural gas transported or passing through a refinery, pipeline, terminal or other facility during a particular period.

SHELL MIDSTREAM PARTNERS, L.P.
TABLE OF CONTENTS

PART I

Unless the context otherwise requires, references in this report to “Shell Midstream Partners,” “the Partnership,” “us,” “our,” “we,” or similar expressions refer to Shell Midstream Partners, L.P. and its subsidiaries. References to “our general partner” or “our sponsor” refer to Shell Midstream Partners GP LLC, a wholly owned subsidiary of Shell Pipeline Company LP (“SPLC”). References to “Shell” or “Parent” refer collectively to Royal Dutch Shell plc and its controlled affiliates, other than us, our subsidiaries and our general partner.

Part I should be read in conjunction with *Part II, Item 7* and with the consolidated financial statements and notes thereto included in *Part II, Item 8* of this report.

Items 1 and 2. BUSINESS AND PROPERTIES

Overview

Shell Midstream Partners, L.P. is a Delaware limited partnership formed by Shell on March 19, 2014 to own and operate pipeline and other midstream assets, including certain assets acquired from SPLC and its affiliates. We conduct our operations either through our wholly owned subsidiary Shell Midstream Operating, LLC ("Operating Company") or through direct ownership. Our general partner is Shell Midstream Partners GP LLC ("general partner" or "sponsor"). Our common units trade on the New York Stock Exchange under the symbol "SHLX."

We are a growth-oriented master limited partnership that owns, operates, develops and acquires pipelines and other midstream assets. As of December 31, 2018, our assets include interests in entities that own crude oil and refined products pipelines and terminals that serve as key infrastructure to (i) transport onshore and offshore crude oil production to Gulf Coast and Midwest refining markets and (ii) deliver refined products from those markets to major demand centers. Our assets also include interests in entities that own natural gas and refinery gas pipelines that transport offshore natural gas to market hubs and deliver refinery gas from refineries and plants to chemical sites along the Gulf Coast.

We generate revenue from the transportation, terminaling and storage of crude oil and refined products through our pipelines and storage tanks, and generate income from our equity and other investments. Our operations consist of one reportable segment. See *Note 1 – Description of the Business and Basis of Presentation* in the *Notes to Consolidated Financial Statements* included in *Part II, Item 8* of this report.

The following table reflects our ownership, and Shell's retained ownership, as of December 31, 2018:

	SHLX Ownership	**Shell's Retained Ownership**
Pecten Midstream LLC ("Pecten")	100.0%	—%
Sand Dollar Pipeline LLC ("Sand Dollar")	100.0%	—%
Triton West LLC ("Triton")	100.0%	—%
Zydeco Pipeline Company LLC ("Zydeco")	92.5%	7.5%
Amberjack Pipeline Company LLC ("Amberjack") Series A/Series B	75.0% / 50.0%	—%
	71.5%	—%

Mars Oil Pipeline Company LLC (“Mars”)		
Odyssey Pipeline L.L.C. (“Odyssey”)	71.0 %	— %
Bengal Pipeline Company LLC (“Bengal”)	50.0 %	— %
Crestwood Permian Basin LLC (“Permian Basin”)	50.0 %	— %
LOCAP LLC (“LOCAP”)	41.48 %	— %
Poseidon Oil Pipeline Company, L.L.C. (“Poseidon”)	36.0 %	— %
Explorer Pipeline Company (“Explorer”)	12.62 %	25.97 %
Proteus Oil Pipeline Company, LLC (“Proteus”)	10.0 %	— %
Endymion Oil Pipeline Company, LLC (“Endymion”)	10.0 %	— %
Colonial Pipeline Company (“Colonial”)	6.0 %	10.12 %
Cleopatra Gas Gathering Company, LLC (“Cleopatra”)	1.0 %	— %

2018 Acquisition

On May 11, 2018, we acquired SPLC's ownership interests in Amberjack, which is comprised of 75% of the issued and outstanding Series A membership interests of Amberjack and 50% of the issued and outstanding Series B membership interests of Amberjack, for an aggregate purchase price of $1,220.0 million (the "May 2018 Acquisition"). We funded the May 2018 Acquisition with $494.0 million in borrowings under our Five Year Revolver due July 2023 (as defined below) and $726.0 million in borrowings under our Five Year Revolver due December 2022 (as defined below).

See *Note 4 – Acquisitions and Divestiture* in the *Notes to Consolidated Financial Statements* in *Part II, Item 8* of this report for additional information.

Organizational Structure

The following simplified diagram depicts our organizational structure as of December 31, 2018:

Our Assets and Operations
Our assets consist of the following systems:

Crude Oil Pipelines
Onshore Crude Pipelines
Delta. Delta is wholly owned by Pecten, and we own a 100% interest in Pecten. SPLC is the operator of Delta.

Delta aggregates volumes from five offshore pipelines, including the Odyssey and Na Kika pipelines and connects offshore oil production in the eastern corridor of the Gulf of Mexico to key onshore markets. The system originates at Main Pass 69P and Main Pass 69A for the transportation of Heavy Louisiana Sweet ("HLS") crude oil from the Gulf of Mexico to onshore demand centers and refineries.
Zydeco. We own a 92.5% interest in Zydeco, which owns the Zydeco pipeline system. SPLC owns the remaining 7.5% interest and is the operator of Zydeco.

Zydeco is a FERC-regulated pipeline system. Zydeco consists of four main pipeline segments that moves light, sweet crude from Houston, Texas to Houma, Louisiana and on to both Clovelly and St. James in Louisiana. Additionally, Zydeco has tankage in Port Neches, Texas and Houma, Louisiana, a dock in Houma, Louisiana and a pipeline that indirectly connects to the offshore Boxer pipeline system. Zydeco's customers include traders, marketers, refiners, producers and affiliates of Shell.
Offshore Crude Pipelines

Auger. Auger is wholly owned by Pecten, and we own a 100% interest in Pecten. SPLC is the operator of Auger. Auger is an offshore Gulf of Mexico corridor pipeline that transports medium sour crude and provides transportation for major oil producers and from multiple production fields in the Gulf of Mexico. Auger shares a complementary strategic connection to the Poseidon pipeline system, which provides certain connected producers the option to access either Poseidon or Auger delivery markets.
Na Kika. Na Kika is wholly owned by Pecten and we own a 100% interest in Pecten. SPLC is the operator of Na Kika.

Na Kika is anchored by the Na Kika platform which serves as a host to several subsea fields and connects to Delta at Main Pass 69 for the delivery of HLS crude oil to onshore demand centers and refineries.
Amberjack. We own 75.0% of the issued and outstanding Series A membership interests of Amberjack and 50.0% of the issued and outstanding Series B membership interests of Amberjack. Chevron Pipe Line Company ("Chevron") owns the remaining membership interests in Amberjack. SPLC is the operator of Amberjack with the exception of the Jack St. Malo Pipeline which is operated by Chevron.
Amberjack transports crude received from several production platforms, including Jack St. Malo, Tahiti, Stampede and Bigfoot, and offers delivery options into multiple pipelines, including Mars and Poseidon, in which we own interests. Through the multiple pipeline connectivity options, Amberjack provides access to onshore destinations such as the entire Mississippi Refining Basin through Clovelly/LOOP and Zydeco's Houma terminal.
Mars. We own a 71.5% interest in Mars, which owns the Mars pipeline system. BP Midstream Partners LP owns the remaining 28.5% interest in Mars. SPLC is the operator of Mars.

Transportation on certain segments of the Mars pipeline system are subject to the jurisdiction of FERC and the Louisiana Public Service Commission. Mars delivers production received from the Mississippi Canyon, Green Canyon and Walker Ridge areas to shore, terminating in salt dome caverns in Clovelly, Louisiana, which is a major trading hub. Mars leases its main storage cavern at Clovelly from LOOP LLC.
Odyssey. We own a 71.0% interest in Odyssey, which owns the Odyssey pipeline system. GEL Odyssey, LLC ("GEL") owns a 29.0% interest in Odyssey. SPLC is the operator of Odyssey.
The Odyssey pipeline system transports crude oil in the offshore eastern Gulf of Mexico to markets in Louisiana. Odyssey provides transportation for major oil producers and from many different production fields in the eastern Gulf of Mexico. Crude oil transported via Odyssey is delivered to the Delta pipeline system for further delivery to onshore demand centers and refineries.
Poseidon. We own a 36.0% interest in Poseidon, which owns the Poseidon pipeline system. GEL Poseidon, LLC ("Genesis") owns the remaining 64.0% interest and is the operator of Poseidon.
The Poseidon pipeline system is a key corridor pipeline, connecting to several Gulf of Mexico fields and delivers via connecting carriers into major crude trading hubs in Texas and Louisiana. Poseidon's largest customers are major oil producers who ship from a variety of production fields in the Gulf of Mexico, many of whom have dedicated production to the pipeline.

Proteus. We own a 10.0% interest in Proteus, which owns the Proteus pipeline system. Mardi Gras Transportation System Inc. ("Mardi Gras") and ExxonMobil Pipeline Company ("ExxonMobil") collectively own the remaining 90.0% interest. SPLC is the operator of Proteus.
The Proteus pipeline system provides transportation for multiple oil producers in the eastern Gulf of Mexico. The pipeline provides access to the Mississippi Canyon area of the Gulf of Mexico. SPLC is currently building the Mattox pipeline which will connect to Proteus and transport all of the volumes from the Appomattox platform.

Endymion. We own a 10.0% interest in Endymion, which owns the Endymion pipeline system. Mardi Gras Endymion Oil Pipeline Company, LLC ("Mardi Gras Endymion") and ExxonMobil collectively own the remaining 90.0% interest. SPLC is the operator of Endymion.

The Endymion pipeline system provides transportation for multiple oil producers in the eastern Gulf of Mexico. Endymion provides access to the Mississippi Canyon area of the Gulf of Mexico and is connected to the LOOP Clovelly storage terminal with access to multiple markets. Endymion leases a cavern from LOOP LLC.

Refined Products Pipelines

Bengal. We own a 50.0% interest in Bengal and Colonial owns the remaining 50.0% interest. Colonial is the system operator for regulatory reporting purposes and operates Bengal's tankage. SPLC operates Bengal's pipelines.

The Bengal pipeline system is a refined products pipeline system that connects four refineries in southern Louisiana to long-haul transportation pipelines. The pipeline system consists of two primary pipelines, one of which connects the Shell and Valero refineries in Norco, Louisiana and also connects the Marathon Petroleum Corporation refinery in Garyville, Louisiana to Bengal's Baton Rouge, Louisiana tankage and the Plantation pipeline. The other primary line connects Shell's Convent, Louisiana refinery to the Plantation pipeline and Bengal's Baton Rouge, Louisiana tankage. The Bengal pipeline system provides transportation for a number of customers from connected refineries and terminals to the Plantation and Colonial pipelines, and from refineries to the Baton Rouge tankage.

Explorer. We own a 12.62% interest in Explorer, which owns the Explorer pipeline system. SPLC owns a 25.97% interest in Explorer, and MPL Investment LLC, Phillips 66 Partners Holdings LLC and Sunoco Pipeline L.P. collectively own the remaining 61.41% interest. The pipeline system is operated by Explorer.

The Explorer pipeline system is a FERC-regulated petroleum products pipeline system, which extends from the Gulf Coast to the Midwest. Explorer transports refined products with more than 70 different specifications for more than 60 different shippers.

Colonial. We own a 6.0% interest in Colonial, which owns the Colonial pipeline system. SPLC owns a 10.12% interest in Colonial, and CDPQ Colonial Partners, LP, Koch Capital Investments Company, LLC, KKR-Keats Pipeline Investors LP and IFM (US) Colonial Pipeline 2, LLC collectively own the remaining 83.88% interest. The pipeline system is operated by Colonial.

The Colonial pipeline system is the largest refined products pipeline in the United States based on barrel-miles transported. Colonial connects refineries along the Gulf Coast to numerous marketing terminals between Houston, Texas and Linden, New Jersey. Colonial transports gasoline, jet fuel, kerosene, home heating oil, diesel fuel and national defense fuels to shipper terminals, and is subject to FERC regulation. Colonial serves a diverse set of customers, including refiners, marketers, airports and airlines.

Terminals and Storage

Triton. We own a 100% interest in Triton which wholly owns the Anacortes (Washington), Colex (Texas), Des Plaines (Illinois), Portland (Oregon) and Seattle (Washington) refined products terminals. Our general partner is the operator of these five terminals.

These terminals receive products from pipelines and, in certain cases, barges, ships or railroads, and distribute them to third parties, who in turn deliver them to end-users and retail outlets. These terminals play a key role in moving products to the end-user market by providing efficient product receipt, storage and distribution capabilities, inventory management, ethanol and biodiesel blending, and other ancillary services that include the injection of various additives.

Lockport. Lockport is wholly owned by Pecten, and we own a 100% interest in Pecten. SPLC is the operator of Lockport.

Lockport is a crude terminal facility located southwest of Chicago that feeds regional refineries and offers strategic trading opportunities. Lockport provides storage services for a number of customers, receives primarily Canadian and Midwest crude and supplies Midwest refineries, and indirectly, a regional distribution hub.

Other Midstream Assets

Refinery Gas Pipeline. Refinery Gas Pipeline is wholly owned by Sand Dollar, and we own a 100% interest in Sand Dollar.

Refinery Gas Pipeline is a network of gas pipelines connecting multiple refineries and plants operated along the Gulf Coast to Shell Chemical sites, including Shell's Norco refinery and Deer Park refinery. The pipelines transport refinery gas which is a mix of methane, natural gas liquids and olefins.

Permian Basin. We own a 50.0% interest in Permian Basin. CPB Member LLC (a jointly owned subsidiary of Crestwood Equity Partners LP and First Reserve) owns the remaining 50.0% interest. The Nautilus gas gathering system is owned by Permian Basin and operated by CPB Operator LLC.
The Nautilus gas gathering system includes receipt point meters, a pipeline, a high-pressure header system, compression capability and a high-pressure delivery point. Nautilus is designed to serve a dedication area of about 100,000 acres in West Texas. The Nautilus system gathers the majority of Shell's operated Delaware Basin gas. Permian Basin has undertaken a project to build the infrastructure to serve approximately 10,500 dedicated acres of development for Halcon Resources Company. The initial field development began in 2018 and will continue through 2019, with full field development taking place from 2020 to 2023. At completion, the expansion is expected to contain gathering lines, receipt points and a compressor station. This project provides an opportunity to secure third party business while we continue to build scale in the Permian.
LOCAP. We own a 41.48% interest in LOCAP. MPLX Operations LLC, an indirect subsidiary of MPLX LP, owns the remaining 58.52% interest. LOOP LLC is the operator of LOCAP.
The LOCAP pipeline connects the LOOP Clovelly Salt Dome storage facility to the active trading hub of St. James, Louisiana. Crude oil arriving at the St. James terminal can be dispatched to any one of four local refineries serving Louisiana and can also be dispatched to other pipeline systems transmitting more than 30% of the nation's refining capacity to refineries throughout the Midwest. The LOCAP pipeline is FERC-regulated.

Cleopatra. We own a 1.0% interest in Cleopatra, which owns the Cleopatra pipeline system. Mardi Gras, BHP Billiton Petroleum (Deepwater) Inc., Enbridge Offshore (Gas Transmission) LLC, and Chevron Midstream Investments LLC collectively own the remaining 99.0% interest in Cleopatra. SPLC is the operator of Cleopatra.
The Cleopatra pipeline system is a gas gathering pipeline and provides gathering and transportation for multiple gas producers and third-party gas shippers.
Pipeline Systems and Terminal Systems

The following table sets forth certain information regarding our pipeline and terminal systems as of December 31, 2018:

Pipeline System/Terminal System	**Diameter (inches)**	**Approximate Length (miles)**	**Approximate Capacity (kbpd)** (2)	**Approximate Tank Storage Capacity (kbls)**
Zydeco crude oil system - Mainlines				
Houston to Port Neches	20	85	250	-
Port Neches to Houma	22	215	375	-
Houma to Clovelly	24	35	500	-
Houma to St James	18	50	260	-
Amberjack crude oil system				
Jack St. Malo	20/24	135	200	-

Tahiti	20/24	55	300	-
ADP 24"	24	100	300	-
Jackalope	20	35	200	-
Genesis	14	30	50	-
Ewing Banks 910	8	5	20	-
Auger crude oil system				
Enchilada Platform to Eugene Island 315	12	35	35	-
Enchilada Platform to Ship Shoal 28P	20	100	200	-
14/16" Auger export line	14/16	40	150	-
Delta crude oil system	16/20	130	420	-
Na Kika crude oil system	18	75	160	-

Mars crude oil system (1)				
Mars TLP to West Delta 143	18	40	100	-
Olympus TLP to West Delta 143	16/18	40	100	-
West Delta 143 to Fourchon	24	55	400	-
Fourchon to Clovelly	24	25	600	-
Bengal product system				
Norco to Baton Rouge tank farm	24	95	305	-
Convent to Baton Rouge tank farm	16	65	210	-
Poseidon crude oil system	Various	365	350	-
Odyssey crude oil system	Various	105	220	-
Proteus crude oil system				
Thunder Horse TLP to South Pass 89E	24/28	70	425	-
Endymion crude oil system				
South Pass 89E to	30	90	425	-

Clovelly				
Cleopatra gas gathering system (2)				
Atlantis TLP to Ship Shoal 332A	16/20	115	500	-
Colonial product system	Various	5,500	2,500	-
Explorer product system	Various	1,830	660	-
Permian Basin gas gathering system (2)	Various	135	220	-
LOCAP pipeline system and storage facility	48	55	1,700	2,600
Lockport terminal system	n/a	n/a	-	2,000
Refinery Gas Pipeline (2)				
Houston Ship Channel	8	10	3,960	-
Texas City	12	35	5,280	-
Garyville - Norco	12	20	3,720	-
Convent to Garyville	12	20	3,840	-
Norco - Paraffinic	8/12	20	3,720	-
Triton refined products terminals				
Anacortes (3)	n/a	n/a	-	-
Colex	n/a	n/a	-	2,585

Des Plaines	n/a	n/a	-	1,060
Portland	n/a	n/a	-	405
Seattle (3)	n/a	n/a	-	490

(1) In addition to the pipeline capacity above, Mars also has storage capacity under its lease of a storage cavern with a related party.
(2) The approximate capacity information presented is in kbpd with the exception of the approximate capacity related to Cleopatra gas gathering system and Permian Basin which are presented in mscf/d, and Refinery Gas Pipeline which is presented in klbs/d.
(3) The Anacortes and Seattle refined products terminals have truck racks which are not included in the above table. The Anacortes refined products terminal does not have tank storage.

Our Relationship with Shell

Shell is one of the world's largest independent energy companies in terms of market capitalization and operating cash flow, and Shell and its joint ventures are a leading producer and transporter of onshore and offshore hydrocarbons as well as a major refiner in the United States. As one of the largest producers in the Gulf of Mexico, Shell is currently developing several deepwater prospects and associated infrastructure. In addition to its offshore production, Shell has significant onshore exploration and production interests and produces crude oil and natural gas throughout North America. Shell's downstream portfolio includes interests in refineries and chemical processing plants throughout the United States. Shell's portfolio of midstream assets provides key infrastructure required to transport and store crude oil and refined products for Shell and third parties. Shell's ownership interests in transportation and midstream assets include crude oil and refined products pipelines, crude oil and refined products terminals, chemicals pipelines, natural gas pipelines and processing plants, and LNG infrastructure assets. Shell or its affiliates are customers of most of our businesses.

SPLC is Shell's principal midstream subsidiary in the United States. As of December 31, 2018, SPLC owns our general partner, a 43.8% limited partner interest in us and all of our incentive distribution rights.

Customers

See *Note 13—Transactions with Major Customers and Concentration of Credit Risk* in the *Notes to Consolidated Financial Statements* included in *Part II, Item 8* of this report.

Competition

Our pipeline systems compete primarily with other interstate and intrastate pipelines and with marine and rail transportation. Some of our competitors may expand or construct transportation systems that would create additional competition for the services we provide to our customers. For example, newly constructed transportation systems in the onshore Gulf of Mexico region may increase competition in the markets where our pipelines operate. In addition, future pipeline transportation capacity could be constructed in excess of actual demand, which could reduce the demand for our services, in the market areas we serve, and could lead to the reduction of the rates that we receive for our services. While we do see some variation from quarter-to-quarter resulting from changes in our customers' demand for transportation, this risk has historically been mitigated by the long-term, fixed rate basis upon which we contracted our capacity. However, two of our transportation services agreements on our Zydeco pipeline system expired in December 2018, and another will expire in mid-2019. These contracts represented approximately 30% of our revenues for both the years ended December 31, 2018 and 2017. Our business may be negatively affected if we are unable to renew or replace our contract portfolio on comparable terms. See "*Management's Discussion and Analysis of Financial Condition and Results of Operations — Changes in Customer Contracting*" for additional information.

Competition among onshore common carrier crude oil pipelines is based primarily on posted tariffs, quality of customer service and connectivity to sources of supply and demand. We believe that our position along the Gulf Coast provides a unique level of service to our customers. Our pipelines and terminals face competition from a variety of alternative transportation methods including rail, water borne movements including barging, shipping and imports and other pipelines that service the same origins or destinations as our pipelines.

Our offshore crude oil pipelines are primarily supported by life-of-lease transportation agreements or direct connected production. However, our offshore pipelines will compete for new production on the basis of geographic proximity to the production, cost of connection, available capacity, transportation rates and access to onshore markets. The principal competition for our offshore pipelines include other crude oil pipeline systems as well as producers who may elect to build or utilize their own production handling facilities. In addition, the ability of our offshore pipelines to access future oil and gas reserves will be subject to our ability, or the producers' ability, to fund the capital expenditures required to connect to the new production. In general, our offshore pipelines are not subject to regulatory rate-making authority, and the rates our offshore pipeline charges for services are dependent on market conditions.

Competition for refined product transportation in any particular area is affected significantly by the end market demand for the volume of products produced by refineries in that area, the availability of products in that area and the cost of transportation to that area from distant refineries. In light of current market conditions, as well as the expiration of certain transportation agreements, we expect greater competition in the markets in which we provide refined product transportation. See "*Management's Discussion and Analysis of Financial Condition and Results of Operations — Factors Affecting Our Business and Outlook*" for additional information.

Our storage terminal competes with surrounding providers of storage tank services. Some of our competitors have expanded terminals and built new pipeline connections, and third parties may construct pipelines that bypass our location. These, or similar events, could have a material adverse impact on our operations.

Our refined products terminals generally compete with other terminals that serve the same markets. These terminals may be owned by major integrated oil and gas companies or by independent terminaling companies. While fees for terminal storage and throughput services are not regulated, they are subject to competition from other terminals serving the same markets. However, our contracts provide for stable, long-term revenue, which is not impacted by market competitive forces.

FERC and State Common Carrier Regulations

Our interstate common carrier and intrastate pipeline systems are subject to economic regulation by various federal, state and local agencies.

14

FERC regulates interstate transportation on our common carrier pipeline systems under the ICA, the EPAct and the rules and regulations promulgated under those laws. FERC regulations require that rates and terms and conditions of service for interstate service pipelines that transport crude oil and refined products (collectively referred to as "petroleum pipelines") and certain other liquids, be just and reasonable and must not be unduly discriminatory or confer any undue preference upon any shipper. FERC's regulations also require interstate common carrier petroleum pipelines to file with FERC and publicly post tariffs stating their interstate transportation rates and terms and conditions of service.

Under the ICA, FERC or interested persons may challenge existing or proposed new or changed rates, services, or terms and conditions of service. FERC is authorized to investigate such charges and may suspend the effectiveness of a new rate for up to seven months. Under certain circumstances, FERC could limit a common carrier pipeline's ability to charge rates until completion of an investigation during which FERC could find that the new or changed rate is unlawful. In contrast, FERC has clarified that initial rates and terms of service agreed upon with committed shippers in a transportation services agreement are not subject to protest or a cost-of-service analysis where the pipeline held an open season offering all potential shippers service on the same terms.

A successful rate challenge could result in a common carrier pipeline paying refunds of revenue collected in excess of the just and reasonable rate, together with interest for the period the rate was in effect, if any. FERC may also order a pipeline to reduce its rates prospectively, and may require a common carrier pipeline to pay shippers reparations retroactively for rate overages for a period of up to two years prior to the filing of a complaint. FERC also has the authority to change terms and conditions of service if it determines that they are unjust or unreasonable or unduly discriminatory or preferential.

We may at any time also be required to respond to governmental requests for information, including compliance audits and rate case reviews conducted by FERC, such as the audit of Explorer and rate complaints filed against Colonial. FERC's Office of Enforcement concluded an audit of Explorer in Docket No. FA16-5-000 for the period January 1, 2013 to December 31, 2016, and issued a letter order on January 12, 2018 adopting the audit's findings and recommendations and requiring Explorer to submit a compliance plan and quarterly compliance reports. Explorer accepted the audit's findings and recommendations, which did not have a financial impact to us. Several shippers on Colonial filed separate complaints with FERC on November 22, 2017, February 2, 2018, March 1, 2018, and April 20, 2018 challenging all of Colonial's tariff rates, as well as its practices and charges related to transmix and product volume loss. The complaints were docketed as Docket Nos. OR18-7-000, OR18-12-000, OR18-17-000, and OR-21-000. On September 20, 2018, FERC issued an order consolidating the complaints into one proceeding and setting the complaints for hearing and settlement judge procedures. Settlement procedures are ongoing, and FERC has not taken any final action on the complaints as of this time.

Additionally, EPAct deemed certain interstate petroleum pipeline rates then in effect to be just and reasonable under the ICA. These rates are commonly referred to as "grandfathered rates." For example, Colonial's rates in effect at the time of the passage of EPAct for interstate transportation service were deemed just and reasonable and therefore are grandfathered. New rates have since been established after EPAct for certain grandfathered pipeline systems such as Zydeco. FERC may change grandfathered rates upon complaint only after it is shown that:

- a substantial change has occurred since enactment in either the economic circumstances or the nature of the services that were a basis for the rate;
- the complainant was contractually barred from challenging the rate prior to enactment of EPAct and filed the complaint within 30 days of the expiration of the contractual bar; or
- a provision of the tariff is unduly discriminatory or preferential.

EPAct required FERC to establish a simplified and generally applicable methodology to adjust tariff rates for inflation for interstate petroleum pipelines. As a result, FERC adopted an indexing rate methodology which, as currently in effect, allows common carriers to change their rates within prescribed ceiling levels that are tied to changes in the U.S. Producer Price Index for Finished Goods ("PPI-FG"). The indexing methodology is applicable to existing rates, including grandfathered rates, with the exclusion of market-based rates. FERC's indexing methodology is subject to review every five years. FERC recently completed its five-year review, revised its indexing methodology and determined that during the five-year period commencing July 1, 2016 and ending June 30, 2021, common carriers charging indexed rates are permitted to adjust their indexed ceilings annually by PPI-FG plus 1.23%. The ruling was appealed and the appeal was denied by the D.C. Circuit Court on November 28, 2017. No further appeal is expected at this time. In May 2018, Zydeco, Mars, LOCAP and Colonial filed with FERC to increase rates subject to FERC's indexing adjustment methodology by approximately 4.4% starting on July 1, 2018.

We cannot predict whether or to what extent the index factor may change in the future. A pipeline is not required to raise its rates up to the index ceiling, but it is permitted to do so; however a pipeline must reduce its indexed rates to the extent they exceed the index ceiling when a negative index applies. Some indexed rates on our systems were reduced in 2016 in response to the lower index ceiling, such as certain spot rates on Zydeco. Rate increases made under the index methodology are presumed to be just and reasonable and require a protesting party to demonstrate that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs. Despite these procedural limits on challenging the indexing of rates, the overall rates are not entitled to any specific protection against rate challenges. Under the indexing rate methodology, in any year in which the index is negative, pipelines must file to lower their rates if those rates would otherwise be above the rate ceiling.

While common carrier pipelines often use the indexing methodology to change their rates, common carrier pipelines may elect to support proposed rates by using other methodologies such as cost-of-service rate making, market-based rates, and settlement rates. A common carrier pipeline can propose a cost-of-service approach when seeking to increase its rates above the rate ceiling (or when seeking to avoid lowering rates to the reduced rate ceiling), but must establish that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology. A common carrier can charge market-based rates if it establishes that it lacks significant market power in the affected markets. A common carrier can establish rates under settlement if agreed upon by all current shippers. Rates for a new service on a common carrier pipeline can be established through a negotiated rate with an unaffiliated shipper.

The rates shown in our FERC tariffs have been established using the indexing methodology, by settlement or by negotiation. If we used cost-of-service rate making to establish or support our rates on our different pipeline systems, the issue of the proper allowance for federal and state income taxes could arise. In 2005, FERC issued a policy statement stating that it would permit common carrier pipelines, among others, to include an income tax allowance in cost-of-service rates to reflect actual or potential tax liability attributable to a regulated entity's operating income, regardless of the form of ownership. Under FERC's policy, a tax pass-through entity seeking such an income tax allowance must establish that its partners or members have an actual or potential income tax liability on the regulated entity's income. Whether a pipeline's owners have such actual or potential income tax liability is subject to review by FERC on a case-by-case basis. Although this policy is generally favorable for common carrier pipelines that are organized as pass-through entities, it still entails rate risk due to FERC's case-by-case review approach and recent changes to FERC's policy following litigation in the U.S. Court of Appeals for the D.C.Circuit. The application of this policy, as well as any decision by FERC regarding our cost of service, is also subject to review in the courts.

Under its current policy, FERC permits regulated interstate oil and gas pipelines to include an income tax allowance in their cost of service used to calculate cost-based transportation rates. The allowance is intended to reflect the actual or potential tax liability attributable to the regulated entity's operating income, regardless of the form of ownership. On July 1, 2016, in United Airlines, Inc. v FERC, the United States Court of Appeals for the D.C. Circuit vacated a pair of FERC orders to the extent they permitted an interstate refined petroleum products pipeline owned by a Master Limited Partnership ("MLP") to include an income tax allowance in its cost-of-service rates. The D.C. Circuit held that FERC had failed to demonstrate that the inclusion of an income tax allowance in the pipeline's rates would not lead to an over-recovery of costs attributable to regulated service. The D.C. Circuit instructed FERC on remand to fashion a remedy to ensure that the pipeline's rates do not allow it to over-recover its costs. Following the D.C. Circuit's decision, FERC issued its Revised Policy Statement on Treatment of Income Taxes in Docket No. PL17-1-000 on March 15, 2018 which eliminates the recovery of an income tax allowance by MLP oil and gas pipelines in cost-of-service-based rates. FERC directed MLP oil pipelines to reflect the elimination of the income tax allowance in their Form No. 6, page 700 reporting and stated that it will incorporate the effects of this Revised Policy on industry-wide oil pipeline costs in the 2020 five-year review of the oil pipeline index level. The Commission also stated that it would address income tax allowances for other "pass-through" entities that are not MLPs in future proceedings. On July 18, 2018, FERC clarified in Order No. 849, which was directed at gas pipelines, that its general disallowance of MLP income tax allowance recovery by providing that an MLP will not be precluded in a future proceeding from making a claim that it is entitled to an income tax allowance based on a demonstration that its recovery of an income tax allowance does not result in a "double-recovery of investors' income tax costs." While FERC has not taken industry-wide action on oil pipeline rates apart from announcing that it would take the MLP income tax allowance elimination into account in the next five-year review of indexed rates in 2020, FERC could require oil pipelines to revise their rates in individual proceedings (including initial rate filing or complaint proceedings) or through other action. To the extent that we charge cost-of-service based rates, those rates could be affected by any changes in FERC's income tax allowance policy to the extent our rates are subject to complaint or challenge by FERC acting on its own initiative, or to the extent that we propose new cost-of-service rates or changes to our existing rates.

On December 22, 2017, federal legislation known as the "Tax Cuts and Jobs Act" (the "TCJA") was enacted, which made various changes to the United States tax laws, including reducing the highest marginal U.S. federal corporate income tax rate from 35% to 21% for tax years beginning after December 31, 2017, adjusting the individual income tax brackets, and establishing limited deductions for certain income from "pass-through" entities. In the Revised Policy Statement on Treatment of Income Taxes issued in Docket No. PL17-1-000, FERC stated that it would address the effect of these tax changes on industry-wide oil pipeline costs in the 2020 five-year review of the oil pipeline index level. FERC also could require oil pipelines to revise their rates in individual proceedings (including initial rate filing or complaint proceedings) or through other action. If the FERC requires us to establish new tariff rates that reflect changes resulting from the TCJA, it is possible that certain tariff rates could be reduced, which could adversely affect our financial position, results of operations and ability to make cash dividends to our Class A shareholders.

On October 20, 2016, FERC issued an Advance Notice of Proposed Rulemaking in Docket No. RM17-1-000 regarding changes to the oil pipeline rate index methodology and data reporting on the Page 700 of the FERC Form No. 6. In an effort to improve the Commission's ability to ensure that oil pipeline rates are just and reasonable under the ICA, the Commission is considering making the following changes to their current indexing methodologies for oil pipelines:

1) Deny index increases for any pipeline whose Form No. 6, Page 700 revenues exceed costs by 15% for both of the prior two years;

2) Deny index increases that exceed by 5% the cost changes reported on Page 700; and

3) Apply the new criteria to costs more closely associated with the pipeline's proposed rates than with total company-wide costs and revenues now reported on Page 700.

Initial comments were filed on January 19, 2017, reply comments were filed on March 17, 2017 and no further action has been taken since. We will continue to monitor developments in this area.

Intrastate services provided by certain of our pipeline systems are subject to regulation by state regulatory authorities, such as the Texas Railroad Commission, which currently regulates Zydeco and Colonial pipeline rates; and the Louisiana Public Service Commission, which currently regulates the Zydeco, Mars, Delta and Colonial pipeline rates. State agencies typically require intrastate petroleum pipelines to file their rates with the agencies and permit shippers to challenge existing rates and proposed rate increases. State agencies may also investigate rates, services, and terms and conditions of service on their own initiative. State regulatory commissions could limit our ability to increase our rates or to set rates based on our costs, or could order us to reduce our rates and require the payment of refunds to shippers.

Further, rate investigations by FERC or a state commission could result in an investigation of our costs, including the:

•overall cost of service, including operating costs and overhead;
•allocation of overhead and other administrative and general expenses to the regulated entity;
•appropriate capital structure to be utilized in calculating rates;
•appropriate rate of return on equity and interest rates on debt;
•rate base, including the proper starting rate base;
•throughput underlying the rate; and
•proper allowance for federal and state income taxes.

Shippers can always file a complaint with FERC or a state agency challenging rates or conditions of services. If they were successful, FERC or a state agency could order reparations or service charge.
Certain pipelines, including Auger, Na Kika, Amberjack, Odyssey, Poseidon, Proteus, Endymion, Cleopatra and parts of Mars, are located offshore in the Outer Continental Shelf. As such, they are not subject to FERC or state rate regulation, but are subject to the Outer Continental Shelf Lands Act ("OCSLA"). Under the OCSLA, we must provide open and nondiscriminatory access to both pipeline owner and non-owner shippers, and comply with other requirements.

Pipeline and Terminal Safety

Our assets are subject to strict safety laws and regulations. Our transportation and storage of crude oil, refined products, and dry gas involves a risk that hazardous liquids or gas may be released into the environment, potentially causing harm to the public or the environment. In turn, such incidents may result in substantial expenditures for response actions, significant government penalties, liability to government agencies for natural resources damages, liability and/or reparations to land owners and significant business interruption. The PHMSA of the DOT has adopted safety regulations with respect to the design, construction, operation, maintenance, inspection and management of most of our assets. In addition, some states have adopted regulations, similar to existing PHMSA regulations, for intrastate gathering and transmission lines. The states in which most of our assets are located, Texas and Louisiana, are among the states that have developed regulatory programs that parallel the federal regulatory scheme and are applicable to intrastate pipelines transporting hazardous liquids and gases. The few assets not covered by PHMSA are regulated by the U.S. Environmental Protection Agency ("EPA") and various state agencies and are designed and maintained to industry accepted codes and standards. The PHMSA regulations contain requirements for the development and implementation of pipeline integrity management programs, which include the inspection and testing of pipelines and necessary maintenance or repairs. These regulations also require that pipeline operation and maintenance personnel meet certain qualifications, are included in a drug and alcohol testing program, and that pipeline operators develop comprehensive spill response plans.

We are subject to regulation by PHMSA under the Natural Gas Pipeline Safety Act of 1968 ("NGPSA") and the Hazardous Liquid Pipeline Safety Act of 1979 ("HLPSA"). The NGPSA delegated to PHMSA through DOT the authority to regulate gas pipelines. The HLPSA delegated to PHMSA through DOT the authority to develop, prescribe, and enforce federal safety standards for the transportation of hazardous liquids by pipeline. Congress also enacted the Pipeline Safety Act of 1992, which added the environment to the list of statutory factors that must be considered in establishing safety standards for hazardous liquid pipelines, required regulations be issued to define the term "gathering line" and establish safety standards for certain "regulated gathering lines," and mandated that regulations be issued to establish criteria for operators to use in identifying and inspecting pipelines located in HCAs. In 1996, Congress enacted the Accountable Pipeline Safety and Partnership Act, which limited the operator identification requirement mandate to pipelines that cross a waterway where a substantial likelihood of commercial navigation exists, required that certain areas where a pipeline rupture would likely cause permanent or long-term environmental damage be considered in determining whether an area is unusually sensitive to environmental damage, and mandated that regulations be issued for the qualification and testing of certain pipeline personnel. The Pipeline Safety Improvement Act of 2002 established mandatory inspections for all U.S. oil transportation pipelines, and some gathering lines in HCAs. In the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006, Congress required mandatory inspections for certain U.S. crude oil and natural gas transmission pipelines in HCAs and mandated that regulations be issued for low-stress hazardous liquids pipelines and pipeline control room management. These assets are also subject to the Pipeline Safety Act of 2011, which reauthorized funding for federal pipeline safety programs through 2015, increased penalties for safety violations, established additional safety requirements for newly constructed pipelines, and required studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines. In 2016, the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (the "Pipes Act") was enacted. The Pipes Act reauthorized the PHMSA through 2019 and imposed a few new mandates on the agency. The law provided the Secretary of the DOT the power to issue pipeline industry wide emergency orders if an incident poses or exposes a particular widespread problem. It also required the PHMSA to develop regulations for the construction and operations of underground natural gas storage facilities and instructed the PHMSA to finish the tasks left over from the 2011 bill. PHMSA will have to be reauthorized by Congress in 2019 and this reauthorization may create new mandates on the agency.

PHMSA administers compliance with these statutes and has promulgated comprehensive safety standards and regulations for the transportation of hazardous liquids by pipeline, including regulations for the design and construction of new pipeline systems or those that have been relocated, replaced, or otherwise changed (Subparts C and D of 49 CFR § 195); pressure testing (Subpart E of 49 CFR § 195); operation and maintenance of pipeline systems, including inspecting and reburying pipelines in the Gulf of Mexico and its inlets, establishing programs for public awareness and damage prevention, managing the integrity of pipelines in HCAs, and managing the operation of pipeline control rooms (Subpart F of 49 CFR § 195); protecting steel pipelines from the adverse effects of internal and external corrosion (Subpart H of 49 CFR § 195); and integrity management requirements for pipelines in HCAs (49 CFR § 195.452). Gas pipelines have similar requirements in 49 CFR 192. On January 19, 2017, PHMSA announced the issuance of new operator qualification rules that clarify the current regulations. This rule was published just before the Trump Administration requirement to withdraw all pending regulations for further review. This rule did not change the operator qualification requirements but did enhance release reporting requirements, placed new training requirements on control room personnel and provided reimbursement provisions for PHMSA oversight of projects totaling $1 billion or more. In addition, on January 30, 2017, the Trump Administration issued an executive order directing agencies to identify two existing regulations to be repealed for every new regulation proposed for notice and comment, along with a zero sum incremental cost requirement for all regulations. This directive applies at the DOT level so it is unclear if 49 CFR 190-199 will be impacted at all as the DOT could pull regulations from other areas such as road transport or hazardous materials handling where there are more regulations that could be considered worthy of repeal in order to cover the repeal and cost cutting directives.

The safety enhancement requirements and other provisions of the Pipeline Safety Act of 2011, as well as any implementation of PHMSA rules thereunder, could require us to install new or modified safety controls, pursue additional capital projects, or conduct maintenance programs on an accelerated basis; any or all of which tasks could result in our incurring increased operating costs that could be significant and have a material adverse effect on our operations or financial position. However, we do not anticipate we would be impacted by these regulatory initiatives to any greater degree than other similarly situated competitors. PHMSA has provided guidance on verification of records related to pipeline maximum allowable operating pressure for gas pipelines and has drafted regulations to formally incorporate this guidance. While this is currently targeted at gas pipelines it could eventually be rolled over to the liquid regulations and we continue to work with industry groups to provide comment and recommendations to PHMSA on proposed regulations to help ensure regulations that will improve safety without providing undue burdens to operators.

We monitor the structural integrity of our pipelines through a program of periodic internal assessments using a variety of internal inspection tools, as well as hydrostatic testing that conforms to federal standards. We accompany these assessments with a comprehensive data integration effort and repair anomalies, as required, to ensure the integrity of the pipeline. We conduct a thorough review of risks to the pipelines and perform sophisticated calculations to establish an appropriate reassessment interval for each pipeline. We use external coatings and impressed current cathodic protection systems to protect against external corrosion. We conduct all cathodic protection work in accordance with National Association of Corrosion Engineers standards and continually monitor, test and record the effectiveness of these corrosion inhibiting systems. We have robust third party damage prevention and public awareness programs to help protect our lines from the risk of excavation and other outside force damage threats. Our tanks are inspected on a routine basis in compliance with PHMSA and EPA regulations. Every tank periodically receives a full out of service, internal inspection per American Petroleum Institute standard 653 and is repaired as necessary.

Product Quality Standards

Refined products that we transport are generally sold by our customers for consumption by the public. Various federal, state and local agencies have the authority to prescribe product quality specifications for refined products. Changes in product quality specifications or blending requirements could reduce our throughput volumes, require us to incur additional handling costs or require capital expenditures. For example, different product specifications for different markets affect the fungibility of the refined products in our system and could require the construction of additional storage. If we are unable to recover these costs through increased revenue, our cash flows and ability to pay cash distributions could be adversely affected. In addition, changes in the product quality of the refined products we receive on our refined product pipeline systems or at our tank farms could reduce or eliminate our ability to blend refined products.

Security

We are also subject to U.S. Department of Homeland Security Chemical Facility Anti-Terrorism Standards, which are designed to regulate the security of high-risk chemical facilities, and to Transportation Security Administration Pipeline Security Guidelines. We have an internal program of inspection designed to monitor and enforce compliance with all of these requirements. We believe that we are in material compliance with all applicable laws and regulations regarding the security of our facilities.

Information Technology and Cybersecurity

We use our Parent's information technology systems, which are increasingly dependent on key contractors supporting the delivery of information technology ("IT") services, and continue to expand in terms of number of systems. Shell, like many other multinational companies, is the target of attempts to gain unauthorized access to its IT systems and our data through various channels, including more sophisticated and coordinated attempts often referred to as advanced persistent threats. Shell continuously measures and, where required, further improves its cyber-security capabilities to reduce the likelihood of successful cyber-attacks. Shell's cyber-security capabilities are embedded into its IT systems and its IT landscape is protected by various detective and protective technologies. The identification and assessment capabilities are built into Shell's support processes and adhere to industry best practices. While cyber-security programs and protocols are in place, we cannot guarantee their effectiveness. A significant cyber-attack could have a material effect on our operations.

While we are not currently subject to U.S. governmental standards for the protection of computer-based systems and technology from cyber threats and attacks, proposals to establish such standards are being considered by the U.S. Congress and by U.S. Executive Branch departments and agencies, including the Department of Homeland Security, and we may become subject to such standards in the future. In addition, the European Union ("EU") General Data Protection Regulation ("GDPR") came into force in May 2018. The GDPR increases penalties up to a maximum of 4%

of global turnover for breach of the regulation. The GDPR requires mandatory breach notification.
Environmental Matters
General. Our operations are subject to extensive and frequently changing federal, state and local laws, regulations and ordinances relating to the protection of the environment. Among other things, these laws and regulations govern the emission or discharge of pollutants into or onto the land, air and water, the handling and disposal of solid and hazardous wastes and the remediation of contamination. As with the industry in general, compliance with existing and anticipated environmental laws and regulations increases our overall cost of business, including our capital costs to construct, maintain, operate and upgrade equipment and facilities. While these laws and regulations affect our maintenance capital expenditures and net income, we

believe they do not affect our competitive position, as the operations of our competitors are similarly affected. We believe our facilities are in substantial compliance with applicable environmental laws and regulations. However, these laws and regulations are subject to changes, or to changes in the interpretation of such laws and regulations, by regulatory authorities, and continued and future compliance with such laws and regulations may require us to incur significant expenditures. Additionally, violation of environmental laws, regulations, and permits can result in the imposition of significant administrative, civil and criminal penalties, injunctions limiting our operations, investigatory or remedial liabilities or construction bans or delays in the construction of additional facilities or equipment. Additionally, a release of hydrocarbons or hazardous substances into the environment could, to the extent the event is not insured, subject us to substantial expenses, including costs to comply with applicable laws and regulations and to resolve claims by third parties for personal injury or property damage, or by the U.S. federal government or state governments for natural resources damages. These impacts could directly and indirectly affect our business and have an adverse impact on our financial position, results of operations and liquidity if we do not recover these expenditures through the rates and fees we receive for our services. We believe our competitors must comply with similar environmental laws and regulations. However, the specific impact on each competitor may vary depending on a number of factors, including, but not limited to, the type of competitor and location of its operating facilities.

We accrue for environmental remediation activities when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. As environmental remediation matters proceed toward ultimate resolution or as additional remediation obligations arise, charges in excess of those previously accrued may be required. New or expanded environmental requirements, which could increase our environmental costs, may arise in the future. We believe we comply with all legal requirements regarding the environment, but since not all of them are fixed or presently determinable (even under existing legislation) and may be affected by future legislation or regulations, it is not possible to predict all of the ultimate costs of compliance, including remediation costs that may be incurred and penalties that may be imposed.

Air Emissions and Climate Change. Our operations are subject to the Clean Air Act and its regulations and comparable state and local statutes and regulations in connection with air emissions from our operations. Under these laws, permits may be required before construction can commence on a new source of potentially significant air emissions, and operating permits may be required for sources that are already constructed. These permits may require controls on our air emission sources, and we may become subject to more stringent regulations requiring the installation of additional emission control technologies.

Future expenditures may be required to comply with the Clean Air Act and other federal, state and local requirements for our various sites, including our pipeline and storage facilities. The impact of future legislative and regulatory developments, if enacted or adopted, could result in increased compliance costs and additional operating restrictions on our business, all of which could have an adverse impact on our financial position, results of operations and liquidity.

In December 2007, Congress passed the Energy Independence and Security Act that created a second Renewable Fuels Standard. This standard requires the total volume of renewable transportation fuels (including ethanol and advanced biofuels) sold or introduced annually in the U.S. to rise to 36 billion gallons by 2022. The requirements could reduce future demand for refined products and thereby have an indirect effect on certain aspects of our business.

Currently, various legislative and regulatory measures to address greenhouse gas emissions (including carbon dioxide, methane and other gases) are in various phases of discussion or implementation in the U.S. These include requirements effective in 2010 to report emissions of greenhouse gases (“GHG”) to the EPA on an annual basis, and proposed federal legislation and regulation as well as state actions to develop statewide or regional programs, each of which require or could require reductions in our greenhouse gas emissions. Requiring reductions in greenhouse gas emissions could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls at our facilities and (iii) administer and manage any greenhouse gas emissions programs, including acquiring emission credits or allotments. These requirements may also significantly affect domestic refinery operations and may have an indirect effect on our business, financial condition and results of operations. We do not believe the federal greenhouse gas reporting rule, as described above, or the greenhouse gas “tailoring” rule, which subjects certain facilities to the

additional permitting obligations under the New Source Review/Prevention of Significant Deterioration and Title V programs of the Clean Air Act based on a facility's greenhouse gas emissions, will have a material adverse effect on our operations.
In addition, the EPA has proposed and may adopt further regulations under the Clean Air Act addressing greenhouse gases, to which some of our facilities may become subject. For example, in May 2016, EPA finalized new rules for volatile organic compound and methane emissions from the oil and gas production, processing, transmission and storage industry. Congress continues to consider legislation on greenhouse gas emissions, which may include a delay in the implementation of greenhouse gas regulations by EPA or a limitation on EPA's authority to regulate greenhouse gases, although the ultimate adoption and form of any federal legislation cannot presently be predicted. In addition, in 2015, the U.S. participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement, which was signed by

the U.S. in April 2016, requires countries to review and “represent a progression” in their intended nationally determined contributions, which set greenhouse gas emission reduction goals, every five years beginning in 2020. In June 2017 the Trump Administration announced its intent to withdraw from the Paris Agreement. Pursuant to the terms of the Paris Agreement, the earliest date the U.S. can withdraw is November 2020. The impact of future regulatory and legislative developments, if adopted or enacted, could result in increased compliance costs, increased utility costs, additional operating restrictions on our business, and an increase in the cost of products generally. Although such costs may impact our business directly or indirectly by impacting our facilities or operations, the extent and magnitude of that impact cannot be reliably or accurately estimated due to the present uncertainty regarding the additional measures and how they will be implemented.

Waste Management and Related Liabilities. To a large extent, the environmental laws and regulations affecting our operations relate to the release of hazardous substances or solid wastes into soils, groundwater and surface water, and include measures to control pollution of the environment. These laws generally regulate the generation, storage, treatment, transportation, and disposal of solid and hazardous waste. They also require corrective action, including investigation and remediation, at a facility where such waste may have been released or disposed.

CERCLA. The Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”), which is also known as Superfund, and comparable state laws impose liability, without regard to fault or to 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 the former and present owner or operator of the site where the release occurred and the transporters and generators 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 classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. In the course of our ordinary operations, we generate waste that falls within CERCLA’s definition of a “hazardous substance” and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites.

RCRA. We also generate solid wastes, including hazardous wastes, that are subject to the requirements of the federal Resource Conservation and Recovery Act (“RCRA”) and comparable state statutes. From time to time, the EPA considers the adoption of stricter disposal standards for non-hazardous wastes. Hazardous wastes are subject to more rigorous and costly disposal requirements than are non-hazardous wastes. Any changes in the regulations could impact our maintenance capital expenditures and operating expenses. We continue to seek methods to minimize the generation of hazardous wastes in our operations.

Hydrocarbon Wastes. We currently own and lease, and SPLC has in the past owned and leased, properties where hydrocarbons are being or for many years have been handled. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or waste may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where these hydrocarbons and wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or wastes was not under our control. These properties and hydrocarbons and wastes disposed thereon may be subject to CERCLA, RCRA, and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater), or to perform remedial operations to prevent further contamination.

Environmental Indemnity. The terms of each acquisition will vary, and in some cases we may receive contractual indemnification from the prior owner or operator for some or all of the liabilities relating to such matters, and in other cases we may agree to accept some or all of such liabilities. We do not believe that the portion of any such liabilities that the Partnership may bear with respect to any such properties previously acquired by the Partnership will have a

material adverse impact on our financial condition or results of operations. For example, in connection with certain of our acquisitions from Shell, Shell agreed to indemnify us for certain environmental liabilities arising before the closing date, subject to customary deductibles and caps.
SPLC's indemnification for breaches of representations or warranties relating to environmental matters in connection with the Initial Public Offering ("IPO") terminated and expired on November 3, 2017.
Water. Our operations can result in the discharge of pollutants, including crude oil and refined products. Regulations under the Water Pollution Control Act of 1972 ("Clean Water Act"), Oil Pollution Act of 1990 ("OPA-90") and state laws impose regulatory burdens on our operations. Spill prevention control and countermeasure requirements of federal laws and some state

laws require containment to mitigate or prevent contamination of navigable waters in the event of an oil overflow, rupture, or leak. For example, the Clean Water Act requires us to maintain Spill Prevention Control and Countermeasure ("SPCC") plans at many of our facilities. We maintain numerous discharge permits as required under the National Pollutant Discharge Elimination System program of the Clean Water Act and have implemented tracking systems to oversee our compliance efforts. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. We believe we are in substantial compliance with applicable storm water permitting requirements.

In addition, the transportation and storage of crude oil and refined products over and adjacent to water involves risk and subjects us to the provisions of OPA-90 and related state requirements. Among other requirements, OPA-90 requires the owner or operator of a tank vessel or a facility to maintain an emergency plan to respond to releases of oil or hazardous substances. Also, in case of any such release, OPA-90 requires the responsible company to pay resulting removal costs and damages. OPA-90 also provides for civil penalties and imposes criminal sanctions for violations of its provisions. We operate facilities at which releases of oil and hazardous substances could occur. We have implemented emergency oil response plans for all of our components and facilities covered by OPA-90 and we have established SPCC plans for facilities subject to Clean Water Act SPCC requirements.

Construction or maintenance of our pipelines, tank farms and storage facilities may impact wetlands, which are also regulated under the Clean Water Act by the EPA and the U.S. Army Corps of Engineers. Regulatory requirements governing wetlands (including associated mitigation projects) may result in the delay of our pipeline projects while we obtain necessary permits and may increase the cost of new projects and maintenance activities.

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

Endangered Species Act. The Endangered Species Act restricts activities that may affect endangered species or their habitats. While some of our facilities are in areas that may be designated as habitat for endangered species, we believe that we are in substantial compliance with the Endangered Species Act. If endangered species are located in areas of the underlying properties where we wish to conduct development activities, such work could be prohibited or delayed or expensive mitigation may be required. In addition, the designation of new endangered species could cause us to incur additional costs or become subject to operating or development restrictions or bans in the affected area.

Inflation

Inflation did not have a material impact on our results of operations in 2018.

Seasonality

The volume of crude oil and refined products transported and stored utilizing our assets is directly affected by the level of supply and demand for crude oil and refined products in the markets served directly or indirectly by our assets. Additionally, producer turnarounds are often planned for certain periods during the year based on optimal, and in some cases, required, weather and working conditions.

Title to Properties and Permits

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the property and, in some instances, these rights-of-way are revocable at the election of the grantor. In many instances, lands over which rights-of-way have been obtained are subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained permits from public authorities to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, and state highways and, in some instances, these permits are revocable at the election of the grantor. We have also obtained permits from railroad companies to cross over or under lands or rights-of-way, many of which are also revocable at the grantor's election. In some states and under some circumstances, we have the right of eminent domain to acquire rights-of-way and lands necessary for our common carrier pipelines.

Future Financial Assurance

22

In July 2016, BOEM issued Notice to Lessees and Operators 2016 NOI ("NTL") that augmented requirements above current levels for the posting of additional financial assurance by offshore lessees, among others, to assure that sufficient funds are available to perform decommissioning obligations with respect to platforms, pipelines and other facilities. In June 2017, BOEM announced that it would extend the NTL implementation timeline beyond the initial June 30, 2017 deadline, except in circumstances where there is a substantial risk of non-performance of decommissioning obligations, citing that more time was needed to work with the industry and other interested parties. There have been no further developments.

Insurance

All assets in which we have an interest are insured for certain property damage, business interruption and third party liabilities, inclusive of cyber event and pollution liabilities, in amounts which management believes are reasonable and appropriate. With the exception of Odyssey, our consolidated assets are insured at the entity level. For Odyssey, as well as our other non-consolidated interests in joint ventures, we carry commercial insurance for our pro rata interests.

Employees

We do not have any employees. We are managed and operated by the directors and officers of our general partner. See *Part III, Item 10. Directors, Executive Officers and Corporate Governance — Management of Shell Midstream Partners, L.P.* in this report.

Control Center Operations

Zydeco, Amberjack, Mars, Odyssey, Bengal's pipeline, Auger, Lockport, Delta, Na Kika, Proteus, Endymion, Cleopatra, Refinery Gas Pipeline and our terminals are operated by SPLC or our general partner pursuant to operating and maintenance agreements. The pipeline, storage and terminal systems that are operated by SPLC are controlled from a central control room located in Houston, Texas. We took over control of central control room activities for Proteus, Endymion and Cleopatra on April 1, 2018. Colonial operates its pipeline system and Bengal's tankage in a similar manner and has its own management team based in Alpharetta, Georgia. Explorer operates its pipeline system in a similar manner and has its own management team and control center operations in Tulsa, Oklahoma. Poseidon is operated by Manta Ray Gathering Company, LLC, LOCAP is operated by LOOP LLC and Permian Basin is operated by CPB Operator LLC.

Website

Our Internet website address is http://www.shellmidstreampartners.com. Information contained on our Internet website is not part of this report. Our Annual Reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to these reports, filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available on our website, free of charge, as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. Alternatively, you may access these reports at the SEC's website at http://www.sec.gov. We also post our beneficial ownership reports filed by officers, directors, and principal security holders under Section 16(a) of the Securities Exchange Act of 1934, corporate governance guidelines, audit committee charter, code of business ethics and conduct, code of ethics for senior financial officers, and information on how to communicate directly with our board of directors on our website.

Item 1A. RISK FACTORS

Limited partner interests are inherently different from the 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 a similar business. If any of the following risks actually occur, they may materially harm our business and our financial condition and results of operations. In this event, we might not be able to pay distributions on our common units, and the trading price of our common units could decline.

Risks Related to Our Business

We may not have sufficient cash available for distribution following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner and its affiliates, to enable us to pay minimum quarterly distributions to our unitholders.

We may not generate sufficient cash flows each quarter to enable us to pay minimum quarterly distributions. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things, our throughput volumes, tariff rates and fees and prevailing economic conditions. In addition, the actual amount of cash flows we generate will also depend on other factors, some of which are beyond our control, including:

- the amount of our operating expenses and general and administrative expenses, including reimbursements to SPLC with respect to those expenses;
- the volume of crude oil, refined products and refinery gas that we transport and the ability of our customers to meet their obligations under our contracts;
- actions by FERC or other regulatory bodies that reduce our rates or increase expenses;
- the amount and timing of expansion capital expenditures and acquisitions we make;
- the amount of maintenance capital expenditures we make;
- our debt service requirements and other liabilities, and restrictions contained in our debt agreements;
- fluctuations in our working capital needs;
- the amount of cash distributed to us by the entities in which we own a noncontrolling interest;
- the amount of cash reserves established by our general partner; and
- changes in, and availability to us, of the equity and debt capital markets.

We do not control certain of the entities that own our assets.

We have no significant assets other than our ownership interests in entities that own crude oil, refined products and refinery gas pipelines and a crude tank storage and terminal system. As a result, our ability to make distributions to our unitholders depends on the performance of these entities and their ability to distribute funds to us. More specifically:

- many of the entities in which we own interests are managed by their respective governing board. Our ability to influence decisions with respect to the operation of such entities varies depending on the amount of control we exercise under the applicable governing agreement;
- we do not control the amount of cash distributed by several of the entities in which we own interests. We may influence the amount of cash distributed through our veto rights over the cash reserves made by certain of these entities;
- we may not have the ability to unilaterally require certain of the entities in which we own interests to make capital expenditures, and such entities may require us to make additional capital contributions to fund operating and maintenance expenditures, as well as to fund expansion capital expenditures, which would reduce the amount of cash otherwise available for distribution by us or require us to incur additional indebtedness;
- the entities in which we own interests may incur additional indebtedness without our consent, which debt payments would reduce the amount of cash that might otherwise be available for distribution;
- our assets are operated by entities that we do not control; and

•the operator of the assets held by each joint venture and the identity of our joint venture partners could change, in some cases without our consent.

For more information on the agreements governing the management and operation of the entities in which we own an interest, see *Part III, Item 13. Certain Relationships and Related Party Transactions, and Director Independence — Agreements with Shell and Part I, Items 1 and 2. Business and Properties — Our Assets and Operations* in this report.

Our ability to renew or replace our third-party contract portfolio on comparable terms could materially adversely affect our business, financial condition, results of operations and cash flows, including our ability to make distributions.

As portions of our third-party contract portfolio come up for replacement or renewal, and capacity becomes available, adverse market conditions may prevent us from replacing or renewing the contracts on comparable terms. For example, two of our transportation services agreements on our Zydeco pipeline system expired in December 2018, and another will expire in the second quarter of 2019. These contracts represented approximately 30% of our revenues for the year ended December 31, 2018. Our ability to achieve favorable terms under these expiring contracts could be affected by many factors, including:

•prolonged lower commodity prices;
•a decrease in demand for our services in the markets we serve;
•increased competition for our services in the markets we serve; and
•actions by FERC or other regulatory bodies that impact our rates or costs.

If we replace the expiring agreements with short-term or spot transportation or storage services, our revenues could be more volatile than they would be under long-term arrangements. If we are unable to replace the expiring agreements or renew the expiring agreements on comparable terms, it could materially adversely affect our business, financial condition, results of operations and cash flows, including our ability to make cash distributions to our unitholders.

If we are unable to obtain needed capital or financing on satisfactory terms to fund expansions of our asset base, our ability to make or increase quarterly cash distributions may be diminished or our financial leverage could increase. Other than our credit facilities, we do not have any contractual commitments with any of our affiliates to provide any direct or indirect financial assistance to us.

We will be required to do one of the following; use cash from our operations, incur borrowings or access the capital markets in order to fund our capital expenditures. If we do not make sufficient or effective capital expenditures, we may be unable to expand our business operations and may be unable to maintain or raise the level of our quarterly cash distributions. The entities in which we own an interest may also incur borrowings or access the capital markets to fund capital expenditures and may require that we fund our proportionate share of such expenditures. Our and their ability to obtain financing or access the capital markets may be limited by our financial condition at such time as well as the covenants in our debt agreements, general economic conditions and contingencies, or other uncertainties that are beyond our control. Furthermore, market demand for equity issued by MLP’s has been significantly lower in recent years than it has been historically, which may make it more challenging for us to finance our capital expenditures and to fund acquisitions with the issuance of equity in the capital markets. Any further decline in the debt and equity capital markets may increase the cost of financing and the risks of refinancing maturity debt. There can be no assurance that the capital markets will be available to us on acceptable terms or at all. The terms of any financing or the use of cash on hand could limit our ability to pay distributions to our common unitholders. Incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional limited partner interests may result in significant common unitholder dilution and increase the aggregate amount of cash required to maintain the then-current distribution rate, which could materially decrease our ability to pay distributions at the then-current distribution rate.

Our operations are subject to many risks and operational hazards. If a significant accident or event occurs that results in a business interruption or shutdown for which we are not adequately insured, our operations and

financial results could be materially and adversely affected.
Our operations are subject to all of the risks and operational hazards inherent in transporting and storing crude oil and refined products, including:

•damages to pipelines, facilities, offshore pipeline equipment and surrounding properties caused by third parties, severe weather, natural disasters, including hurricanes, and acts of terrorism;

•maintenance, repairs, mechanical or structural failures at our or SPLC's facilities or at third-party facilities on which our customers' or our operations are dependent, including electrical shortages, power disruptions, power grid failures and planned turnarounds;
•damages to, loss of availability of and delays in gaining access to interconnecting third-party pipelines, terminals and other means of delivering crude oil, refined products and refinery gas;
•costs and liabilities in responding to any soil and groundwater contamination that occurs on our terminal properties, even if the contamination was caused by prior owners and operators of our terminal system;
•disruption or failure of information technology systems and network infrastructure due to various causes, including unauthorized access or attack of the central control room from which some of our pipelines are remotely controlled;
•leaks of crude oil or refined products as a result of the malfunction or age of equipment or facilities;
•unexpected business interruptions;
•curtailments of operations due to severe seasonal weather; and
•riots, strikes, lockouts or other industrial disturbances.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage, as well as business interruptions or shutdowns of our facilities. Any such event or unplanned shutdown could have a material adverse effect on our business, financial condition and results of operations.

For example, beginning in the latter part of 2017 we ran an in-line inspection tool on our Zydeco pipeline system, hydro-tested the system and invested in additional equipment to mitigate the effects of pressure cycling in the future. The hydro-test resulted in the Zydeco pipeline from Houston, Texas and Houma, Louisiana being out of service for 49 days in the first quarter of 2018. The impact to net income and cash available for distribution was approximately $60.0 million in the first quarter of 2018. Final remediation activities were completed in the second quarter of 2018 with no material impact.

If third-party pipelines, production platforms, refineries, caverns and other facilities interconnected to our pipelines, Triton's refined product terminal and Lockport's terminal facilities become unavailable to transport, produce, refine or store crude oil, or produce or transport refined product, our revenue and available cash could be adversely affected.

We depend upon third-party pipelines, production platforms, refineries, caverns and other facilities that provide delivery options to and from our pipelines and terminal facilities. For example, Mars depends on a natural gas supply pipeline connecting to the West Delta 143 platform to power its equipment to deliver the volumes it transports to salt dome caverns in Clovelly, Louisiana. Similarly, shutdown or blockage of pipelines moving offshore gas can result in curtailment or shut-in of offshore crude production. Because we do not own these third-party pipelines, production platforms, refineries, caverns or facilities, their continuing operation is not within our control. For example, production platforms in the offshore Gulf of Mexico may be required to be shut in by BSEE or BOEM of the U.S. Department of the Interior following incidents such as loss of well control. If these or any other pipeline or terminal connection were to become unavailable for current or future volumes of crude oil or refined product due to repairs, damage to the facility, lack of capacity, shut in by regulators or any other reason, or if caverns to which we connect have cracks, leaks or leaching or require shut-in due to regulatory action or changes in law, our ability to operate efficiently and continue to store or ship crude oil and refined products to major demand centers could be restricted, thereby reducing revenue. Disruptions at refineries that use our pipelines, such as strikes or ship channel incidents, can also have an adverse impact on the volume of products we ship. Increases in the rates charged by the interconnected pipelines for transportation to and from our terminal facilities may reduce the utilization of our terminals. Our refined products terminals are limited to a 5% reduction in payments by the customer due to force majeure incidents. Any temporary or permanent interruption at any key pipeline or terminal interconnect, at any key production platform or refinery, at caverns to which we deliver, termination of any connection agreement, or adverse change in the terms and conditions of service, could have a material adverse effect on our business, results of operations, financial condition or cash flows, including our ability to make cash distributions to our unitholders.

In the second quarter of 2018, Mars experienced lower volumes due to a planned producer turnaround. The impact to net income and cash available for distribution was approximately $7.0 million in 2018. Volumes returned to anticipated levels in the third quarter of 2018.

In November 2017, the Enchilada platform in Garden Banks Block 128 experienced a fire that resulted in the shut-in of all production flowing through Auger. The impact to net income and cash available for distribution in 2018 was approximately

$11.0 million. The platforms contributing a majority of Auger's daily throughput have returned to service in the first quarter of 2018, and the remaining impacted platforms resumed production in the third quarter of 2018.

In the beginning of the fourth quarter of 2017, fields connecting to Odyssey went offline due to operational issues and came back online in the third quarter of 2018. The impact to net income and cash available for distribution for Odyssey and Delta was approximately $9.0 million in 2018.

If we are unable to make acquisitions on economically acceptable terms from Shell or third parties, our future growth would be limited, and any acquisitions we may make may reduce, rather than increase, our cash flows and ability to make distributions to unitholders.

Our strategy to grow our business and increase distributions to unitholders is dependent in part on our ability to make acquisitions that result in an increase in cash available for distribution per unit. The consummation and timing of any future acquisitions will depend upon, among other things, whether we are able to:

- identify attractive acquisition candidates;
- negotiate acceptable purchase agreements;
- obtain financing for these acquisitions on economically acceptable terms, which may be more difficult at times when the capital markets are less accessible; and
- outbid any competing bidders.

We can offer no assurance that we will be able to successfully consummate any future acquisitions, whether from Shell or any third parties. If we are unable to make future acquisitions, our future growth and ability to increase distributions will be limited. Furthermore, even if we do consummate acquisitions that we believe will be accretive, they may in fact result in a decrease in cash available for distribution per unit as a result of incorrect assumptions in our evaluation of such acquisitions or unforeseen consequences or other external events beyond our control. We may incur difficulties and additional costs in connection with integrating an acquired asset or entity. Acquisitions involve numerous risks, inefficiencies and unexpected costs and liabilities.

Any significant decrease in production of crude oil in areas in which we operate could reduce the volumes of crude oil we transport and store, which could adversely affect our revenue and available cash.

Our crude oil pipelines and terminal system depend on the continued availability of crude oil production and reserves, particularly in the Gulf of Mexico. Low prices for crude oil could adversely affect development of additional reserves and continued production from existing reserves that are accessible by our assets.

Crude oil prices have fluctuated significantly over the past few years, often with drastic moves in relatively short periods of time. During 2018, prices slowly increased from 2017 levels until the middle of the fourth quarter, at which point there was a steep decline. The current global geopolitical and economic uncertainty may contribute to continued volatility in financial and commodity markets in the near to medium term. High, low and average daily prices for West Texas Intermediate ("WTI") crude oil at Cushing, Oklahoma during January 2019, 2018 and 2017 were as follows:

	WTI Crude Oil Prices		
	High	**Average**	**Low**
January 2019	$ 54.18	$ 51.38	$ 46.31
2018	77.41	65.23	44.48
2017	60.46	50.80	42.48

In general terms, the prices of crude oil and other hydrocarbon products fluctuate in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control. These factors impacting crude oil prices include worldwide economic conditions; weather conditions and seasonal trends; the levels of domestic production and consumer demand; the availability of imported crude oil; the availability of transportation systems with adequate capacity; the volatility and uncertainty of regional basis differentials and premiums; actions by the Organization of the Petroleum Exporting Countries and other oil producing nations; the price and availability of alternative energy, including alternative energy which may benefit from government subsidies; the effect of energy conservation measures; the strength of the U.S. dollar; the nature and extent of governmental regulation and taxation; and the anticipated future prices of crude oil and other commodities.

Lower crude oil prices, or expectations of declines in crude oil prices, have had and may continue to have a negative impact on exploration, development and production activity, particularly in the continental U.S. If lower prices are sustained, it could lead to a material decrease in such activity both onshore continental U.S. and in the Gulf of Mexico. Sustained reductions in exploration or production activity in our areas of operation could lead to reduced utilization of our pipeline and terminal systems or reduced rates under renegotiated transportation or storage agreements. Our customers may also face liquidity and credit issues that could impair their ability to meet their payment obligations under our contracts or cause them to renegotiate existing contracts at lower rates or for shorter terms. These conditions may lead some of our customers, particularly customers that are facing financial difficulties, to seek to renegotiate existing contracts on terms that are less attractive to us. Any such reduction in demand or less attractive terms could have a material adverse effect on our results of operations, financial position and ability to make or increase cash distributions to our unitholders.

In addition, production from existing areas with access to our pipeline and terminal systems will naturally decline over time. The amount of crude oil reserves underlying wells in these areas may also be less than anticipated, and the rate at which production from these reserves declines may be greater than anticipated. Accordingly, to maintain or increase the volume of crude oil transported, or throughput, on our pipelines, or stored in our terminal system, and cash flows associated with the transportation and storage of crude oil, our customers must continually obtain new supplies of crude oil. In addition, we will not generate revenue under our life-of-lease transportation agreements that do not include a guaranteed return to the extent that production in the area we serve declines or is shut in.

If new supplies of crude oil are not obtained, including supplies to replace any decline in volumes from our existing areas of operations, the overall volume of crude oil transported or stored on our systems would decline, which could have a material adverse effect on our business, results of operations, financial condition or cash flows, including our ability to make cash distributions to our unitholders.

Any significant decrease in the demand for crude oil, refined products and refinery gas could reduce the volumes of crude oil, refined products and refinery gas that we transport, which could adversely affect our revenue and available cash.

The volumes of crude oil, refined products and refinery gas that we transport depend on the supply and demand for crude oil, gasoline, jet fuel, refinery gas and other refined products in our geographic areas. Demand for crude oil, refined products and refinery gas may decline in the areas we serve as a result of, decreased production by our customers, depressed commodity price environment, increased competition, and adverse economic factors, affecting the exploration, production and refining industries.

Further, crude oil, refined products and refinery gas compete with other forms of energy available to users, including electricity, coal, other fuels and alternative energy. Increased demand for such forms of energy at the expense of crude oil, refined products and refinery gas could lead to a reduction in demand for our services.

If the demand for crude oil, refined products or refinery gas decreases significantly, or if there were a material increase in the price of crude oil supplied to our customers' refineries without an increase in the value of the products produced by those refineries, either temporary or permanent, it may cause our customers to reduce production of refined products at their refineries. If production of refined products declines, there would likely be a reduction in the volumes of crude oil and refined products that we transport. Any such reduction could have a material adverse effect on our results of operations, financial position and ability to make cash distributions to our unitholders.

Our insurance policies do not cover all losses, costs or liabilities that we may experience, and insurance companies that currently insure companies in the energy industry may cease to do so or substantially increase premiums.

With the exception of Odyssey, our consolidated assets are insured at the entity level for certain property damage, business interruption and third-party liabilities, which includes pollution liabilities. For Odyssey, as well as our other non-consolidated interests in joint ventures, the current owners are required to carry insurance for their pro rata interest. We carry commercial insurance for our pro rata interests, which will increase our operations and maintenance expenses.

All of the insurance policies relating to our assets and operations are subject to policy limits. In addition, the waiting period under the business interruption insurance policies of the entities in which we own an interest is 60 days. We and the entities in which we own an interest do not maintain insurance coverage against all potential losses and could suffer losses for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Changes in the insurance markets subsequent to the September 11, 2001 terrorist attacks and certain hurricanes and natural disasters have made it more difficult and more expensive to obtain certain types of coverage. The occurrence of an event that is not fully covered by insurance, or failure by our insurer to honor its coverage commitments for an insured event, could have a material adverse effect on our business, financial condition and results of operations. Insurance companies may reduce the insurance capacity they are willing to offer or may demand significantly higher premiums or deductibles to cover our assets. If significant changes in the number or financial solvency of insurance underwriters for the energy industry occur, we may be unable to obtain and maintain adequate insurance at a reasonable cost. There is no assurance that the insurers of the entities in which we own an interest will renew their insurance coverage on acceptable terms, if at all, or that the entities in which we own an interest will be able to arrange for adequate alternative coverage in the event of non-renewal. The unavailability of full insurance coverage to cover events in which the entities in which we own an interest suffer significant losses could have a material adverse effect on our business, financial condition and results of operations, including our ability to make cash distributions to our unitholders.

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

We are subject to the risks of loss resulting from nonpayment or nonperformance by our customers. If any of our most significant customers default on their obligations to us, our financial results could be adversely affected. Our customers may be highly leveraged and subject to their own operating and regulatory risks. If any of our customers were to seek protection under the U.S. Bankruptcy Code or other insolvency laws, the court could void the customer's contracts with us or allow our customer to reject such contracts. For certain of our pipelines, we may have a limited pool of potential customers and may be unable to replace any customers who default on their obligations to us. Therefore, any material deterioration in the creditworthiness of our customers or any material nonpayment or nonperformance by our customers could have a material adverse effect on our business, financial condition and results of operations, including our ability to make cash distributions to our unitholders.

In addition, we are subject to political and economic risks that impact our customers. For example, the U.S. has gradually expanded sanctions that have impacted Petroleos de Venezuela, S.A. ("PdVSA") and its subsidiaries as well as the Government of Venezuela. On January 28, 2019, the Trump Administration designated PdVSA on the Specifically Designated Nationals and Blocked Persons List administered by the U.S. Treasury Department's Office of Foreign Asset Control ("OFAC"). As a result, U.S. persons are generally prohibited from engaging in transactions with PdVSA and its majority-owned subsidiaries. Certain of our customers are subsidiaries of PdVSA and, as a result, we and certain of our customers may be impacted if the General Licenses allowing for the temporary continuation of operations or engagements with PdVSA and its majority-owned subsidiaries expire in 2019. Therefore, absent further action by the U.S. and OFAC, the loss of customers as a result of the sanctions could have a material adverse effect on our business, financial condition and results of operations, including our ability to make cash distributions to our unitholders.

Our expansion of existing assets and construction of new assets may not result in revenue increases and will be subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our operations and financial condition.

In order to optimize our existing asset base, we intend to expand our existing pipelines and terminals, such as by adding horsepower, pump stations, new connections or additional tank storage. We also intend to evaluate and capitalize on organic opportunities for expansion projects in order to increase revenue on our assets. If we undertake these projects, they may not be completed on schedule or at all or at the budgeted cost.

These expansion projects involve numerous regulatory, environmental, political and legal uncertainties, most of which are beyond our control.

Moreover, we may not receive sufficient long-term contractual commitments or spot shipments from customers to provide the revenue needed to support projects, and we may be unable to negotiate acceptable interconnection agreements with third-party pipelines to provide destinations for increased throughput. Even if we receive such commitments or spot shipments or make such interconnections, we may not realize an increase in revenue for an extended period of time. As a result, new or expanded facilities may not be able to attract enough throughput to achieve our expected investment return, which could have a material adverse effect on our business, financial condition and results of operations, including our ability to make cash distributions to our unitholders.

We do not own all of the land on which our assets are located, which could result in disruptions to our operations.
We do not own all of the land on which our assets are located, and we are, therefore, subject to the possibility of more onerous terms and increased costs to retain necessary land use if we do not have valid leases or rights-of-way or if such leases or rights-of-way lapse or terminate. We obtain the rights to construct and operate our assets on land owned by third parties and governmental agencies, and some of our agreements may grant us those rights for only a specific period of time. Our loss of these or similar rights, through our inability to renew leases, right-of-way contracts or otherwise, or inability to obtain

easements at reasonable costs could have a material adverse effect on our business, results of operations, financial condition and cash flows, including our ability to make cash distributions to our unitholders.

We are subject to pipeline safety laws and regulations, compliance with which may require significant capital expenditures, increase our cost of operations and affect or limit our business plans.

Our interstate and offshore pipeline operations are subject to pipeline safety regulations administered by the PHMSA of the DOT. These laws and regulations require us to comply with a significant set of requirements for the design, construction, operation, maintenance, inspection and management of our crude oil, refined products and refinery gas pipelines.

Certain aspects of our offshore pipeline operations, such as new construction and modification, are also regulated by BOEM, BSEE and the U.S. Coast Guard.

PHMSA has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines, with enhanced measures required for pipelines located where a leak or rupture could harm an HCA. The regulations require operators to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could affect an HCA;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

In addition, states have adopted regulations similar to existing PHMSA regulations for intrastate pipelines. For example, our intrastate pipelines in Louisiana are subject to pipeline safety regulations, including integrity management regulations administered by the Office of Conservation of the Louisiana Department of Natural Resources.

At this time, we cannot predict the ultimate cost of compliance with applicable pipeline integrity management regulations, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines. In addition, our actual implementation costs may be affected by industry-wide demand for the associated contractors and service providers. Additionally, should any of our assets fail to comply with PHMSA regulations, they could be subject to shut-down, pressure reductions, penalties and fines.

Changes to pipeline safety laws and regulations that result in more stringent or costly safety standards could have a significant adverse effect on us and similarly situated midstream operators. For example, PHMSA has announced that it anticipates the issuance of the Pipeline Safety: Safety of Hazardous Liquids Pipelines final rule in 2019. The requirements for regulatory reduction put in place by the Trump administration delayed this rule from the anticipated 2018 release; with reauthorization in 2019 it is expected that PHMSA will work diligently toward issuance of the final rule. The final rule addressed topics such as: reporting requirements for gravity and gathering lines, inspections of pipelines following extreme weather events, periodic assessment of pipelines not currently subject to integrity management, repair criteria, expanded use of leak detection systems, increased use of in-line inspection tools and other clarifications. PHMSA has drafted similar regulations for refinery gas pipelines. As drafted those rules are expected to have minimal impact to the assets we operate.

In this climate of increasingly stringent regulation, pipeline failures or failures to comply with applicable regulations could result in shut-downs, capacity constraints or operational limitations to our pipelines. Should any of these risks materialize, it could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Compliance with and changes in environmental laws and regulations, including proposed climate change laws and regulations, could adversely affect our performance. Our customers are also subject to environmental laws and regulations, and any changes in these laws and regulations, including laws and regulations related to hydraulic fracturing, could result in significant added costs to comply with such requirements and delays or curtailment in

pursuing production activities, which could reduce demand for our services.

The principal environmental risks associated with our operations are emissions into the air and releases into the soil, surface water or groundwater. Our operations are subject to extensive environmental laws and regulations, including those relating to the discharge and remediation of materials in the environment, GHG emissions, waste management, species and habitat preservation, pollution prevention, pipeline integrity and other safety-related regulations and characteristics and composition of fuels. Certain of these laws and regulations could impose obligations to conduct assessment or remediation efforts at our facilities or third-party sites where we take wastes for disposal or where our wastes migrated, or could impose strict liability on us for the conduct of third parties or for actions that complied with applicable requirements when taken, regardless of negligence or fault. Our offshore operations are also subject to laws and regulations protecting the marine environment administered by the U.S. Coast Guard and BOEM. Failure to comply with these laws and regulations could lead to administrative, civil or criminal penalties or liability and imposition of injunctions, operating restrictions or the loss of permits.

Because environmental laws and regulations are becoming more stringent and new environmental laws and regulations are continuously being enacted or proposed, the level of expenditures required for environmental matters could increase in the future. Current and future legislative action and regulatory initiatives could result in changes to operating permits, material changes in operations, increased capital expenditures and operating costs, increased costs of the goods we transport, and decreased demand for products we handle that cannot be assessed with certainty at this time. We may be required to make expenditures to modify operations or install pollution control equipment or release prevention and containment systems that could materially and adversely affect our business, financial condition, results of operations and liquidity if these expenditures, as with all costs, are not ultimately reflected in the tariffs and other fees we receive for our services. For example, the EPA has, in recent years, adopted final rules making more stringent the National Ambient Air Quality Standards for ozone, sulfur dioxide and nitrogen dioxide. Emerging rules implementing these revised air quality standards may require us to obtain more stringent air permits and install more stringent controls at our operations, which may result in increased capital expenditures.

Climate change legislation and regulations to address GHG emissions are in various phases of discussion or implementation in the United States. The outcome of federal, state and regional actions to address climate change could result in a variety of regulatory programs including potential new regulations to control or restrict emissions, taxes or other charges to deter emissions of GHGs, energy efficiency requirements or alternative energy requirements to reduce demand, or other regulatory actions. These actions could result in increased compliance and operating costs or could adversely affect demand for the crude oil and refined products that we transport. Additionally, adoption of federal, state or regional requirements mandating a reduction in GHG emissions could have far-reaching impacts on the energy industry and the U.S. economy. We cannot predict the potential impact of such laws or regulations on our future consolidated financial condition, results of operations or cash flows. Finally, some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, it is uncertain if they would have an adverse effect on our financial condition and operations.

Our customers are also subject to environmental laws and regulations that affect their businesses, and changes in these laws or regulations could materially adversely affect their businesses or prospects. Our crude oil pipelines serve customers who depend on production techniques, such as hydraulic fracturing, that are currently being scrutinized by federal, state and local authorities and that could be subjected to increased regulatory costs, delays or liabilities. Any changes in laws or regulations that impose significant costs or liabilities on our customers, or that result in delays, curtailments or cancellations of their projects, could reduce their demand for our services and materially adversely affect our business, results of operations, financial position or cash flows, including our ability to make cash distributions to our unitholders.

Subsidence and coastal erosion could damage our pipelines along the Gulf Coast and offshore and the facilities of our customers, which could adversely affect our operations and financial condition.

Our pipeline operations along the Gulf Coast and offshore could be impacted by subsidence and coastal erosion. Such processes could cause serious damage to our pipelines, which could affect our ability to provide transportation services. Additionally, such processes could impact our customers who operate along the Gulf Coast, and they may be unable to utilize our services. Subsidence and coastal erosion could also expose our operations to increased risks associated with severe weather conditions, such as hurricanes, flooding and rising sea levels. As a result, we may incur significant costs to repair and preserve our pipeline infrastructure. Such costs could adversely affect our business, financial condition, results of operation or cash flows, including our ability to make cash distributions to our unitholders.

We may be unable to obtain or renew permits necessary for our operations or for growth and expansion projects, which could inhibit our ability to do business.

Our facilities operate under a number of federal and state permits, licenses and approvals with terms and conditions containing a significant number of prescriptive limits and performance standards in order to operate. In addition, we implement maintenance, growth and expansion projects as necessary to pursue business opportunities, and these projects often require similar permits, licenses and approvals. These permits, licenses, approval limits and standards require a significant amount of monitoring, record keeping and reporting in order to demonstrate compliance with the underlying permit, license, approval limit or standard. Noncompliance or incomplete documentation of our compliance status may result in the imposition of fines, penalties and injunctive relief. A decision by a government agency to deny or delay issuing a new or renewed permit or approval, or to revoke or substantially modify an existing permit or approval, could have a material adverse effect on our ability to continue operations and on our business, financial condition, results of operations and cash flows, including our ability to make cash distributions to our unitholders.

Our assets were constructed over many decades which may cause our inspection, maintenance or repair costs to increase in the future. In addition, there could be service interruptions due to unknown events or conditions or increased downtime associated with our pipelines that could have a material adverse effect on our business and results of operations.

Our pipelines and storage terminals were constructed over many decades. Pipelines and storage terminals are generally long-lived assets, and construction and coating techniques have varied over time. Depending on the era of construction, some assets will require more frequent inspections, which could result in increased maintenance or repair expenditures in the future. Any significant increase in these expenditures could adversely affect our business, results of operations, financial condition or cash flows, including our ability to make cash distributions to our unitholders.

The tariff rates and rules and regulations for service of our regulated assets, as well as our business practices for our regulated assets, are subject to review, audit and possible adjustment by federal and state regulators, which could adversely affect our revenue and our ability to make distributions to our unitholders.

We provide both interstate and intrastate transportation services for refined products and crude oil. Our interstate and intrastate pipelines are common carriers and are required to provide service to any shipper similarly situated to an existing shipper that requests transportation services on our pipelines.

Zydeco, Bengal, Colonial, Explorer and portions of Mars provide interstate transportation services that are subject to regulation by FERC under the ICA. FERC uses prescribed rate methodologies for developing and changing regulated rates for interstate pipelines. Shippers may protest (and FERC may investigate) the lawfulness of existing, new or changed tariff rates. FERC can suspend new or changed tariff rates, rules and regulations for up to seven months and can allow new rates to be implemented subject to refund of amounts collected in excess of the rate ultimately found to be just and reasonable. Shippers may also file complaints that existing rates are unjust and unreasonable. If FERC finds a rate to be unjust and unreasonable, it may order payment of reparations for up to two years prior to the filing of a complaint or investigation, and FERC may prescribe new rates prospectively. On November 3, 2015, Colonial made a rules and regulations tariff filing with FERC in Docket No. 16-61-000 to change, among other things, its capacity allocation and minimum tender procedures. Colonial made the filing to address chronic allocation issues on its system. FERC rejected the package of proposals in Colonial’s filing and a revised proposal filed on March 23, 2016, but accepted, in an order issued on January 13, 2017, certain aspects of Colonial’s November 3, 2015 filing related to the minimum tender requirement for the Woodbury-Linden Main Line and the rounding increment used to allocate capacity on Main Lines 1 & 2.

The TCJA reduced the highest marginal U.S. federal corporate income tax rate from 35% to 21% for tax years beginning after December 31, 2017. In the Revised Policy Statement on Treatment of Income Taxes issued in Docket No. PL17-1-000, FERC states that it would address the effect of the tax changes on industry-wide oil pipeline costs in the 2020 five-year review of the oil pipeline index level. FERC also could require oil pipelines to revise their rates in individual proceedings (including initial rate filing or complaint proceedings) or through other action. Certain of our current tariff rates on file with FERC may reflect the federal income tax rates that were in effect at the time those tariff rates were established. As with any regulatory requirements promulgated by FERC, if FERC requires us to establish new tariff rates that reflect the current federal corporate income tax rate, it is possible the rates would be reduced, which could adversely affect our financial position, results of operation and ability to make cash distributions to our unitholders.

We may at any time also be required to respond to governmental requests for information, including compliance audits and rate case reviews conducted by FERC, such as the audit of Explorer and rate complaints filed against

Colonial. FERC’s Office of Enforcement concluded an audit of Explorer in Docket No. FA16-5-000 for the period January 1, 2013 to December 31, 2016, and issued a letter order on January 12, 2018 adopting the audit’s findings and recommendations. Explorer accepted the audit’s findings and recommendations, which did not have a financial impact to us. Several shippers on Colonial filed separate complaints with FERC on November 22, 2017, February 2, 2018, March 1, 2018, and April 20, 2018 challenging all of Colonial’s tariff rates, as well as its practices and charges related to transmix and product volume loss. The complaints were docketed as Docket Nos. OR18-7-000, OR18-12-000, OR18-17-000, and OR-21-000. On September 20, 2018, FERC issued an order consolidating the complaints into one proceeding and setting the complaints for hearing and settlement judge procedures. Settlement procedures are ongoing, and FERC has not taken any final action on the complaints as of this time.

State agencies may regulate the rates, terms and conditions of service for our pipelines offering intrastate transportation services, and such agencies could limit our ability to increase our rates or order us to reduce our rates and pay refunds to shippers. State agencies can also regulate whether a service may be provided or cancelled. The FERC and most state agencies support light-handed regulation of common carrier pipelines and have generally not investigated the rates, terms and conditions of service of pipelines in the absence of shipper complaints, and generally resolve complaints informally. Louisiana's Public Service Commission has a more stringent review of rate increases and may prohibit or limit future rate increases for intrastate movements regulated by Louisiana.

Under our agreements with certain of our customers, we and the customer have agreed to base tariff rates for some of our pipelines, and our customers have agreed not to challenge the base tariff rates or changes to those rates during the term of the agreements, subject to certain exceptions. Some of these agreements and the underlying rates have been approved by FERC under a declaratory order. These agreements do not, however, prevent any other new or prospective shipper, FERC or a state agency from challenging our tariff rates or our terms and conditions of service on rates or services not covered by these agreements. Following the reversal of Zydeco, in December 2013, SPLC filed three related tariffs with FERC to establish rates for uncommitted service on Zydeco. The filed rates became effective on December 12, 2013 and were jointly protested in a FERC filing by Anadarko Petroleum Corporation, ConocoPhillips Company, Marathon Oil Company and Pioneer Natural Resources USA, Inc. (collectively, the "Liquid Shipper Group"). Zydeco later adopted those tariffs as part of its acquisition of the Ho-Ho pipeline, and Zydeco's rates for uncommitted service were also protested by the Liquid Shipper Group under Docket Nos. IS14-607-000, IS14-608-000, IS14-609-000, and IS14-610-000, filed on July 31, 2014. After adoption of the SPLC tariffs by Zydeco, the protest against SPLC was dismissed. On August 15, 2015, all parties reached a settlement agreement establishing maximum uncommitted rates for uncommitted shippers, providing rate refunds plus interest, and establishing a two year rate moratorium during which neither Zydeco or the Liquid Shipper Group may file to change or challenge the settlement rates, among other terms. FERC accepted the settlement by a letter order, and the approved settlement, including the revised rates, went into effect December 1, 2016.

Further, rate investigations by FERC or a state commission could result in an investigation of our costs, including the:

- overall cost of service, including operating costs and overhead;
- allocation of overhead and other administrative and general expenses to the regulated entity;
- appropriate capital structure to be utilized in calculating rates;
- appropriate rate of return on equity and interest rates on debt;
- rate base, including the proper starting rate base;
- throughput underlying the rate; and
- proper allowance for federal and state income taxes.

Shippers can always file a complaint with the FERC or a state agency challenging rates or conditions of services. If they were successful, the FERC or state agency could order reparations. A successful challenge of any of our rates, or any changes to FERC's approved rate or index methodologies, could adversely affect our revenue and our ability to make distributions to our unitholders. Similarly, if state agencies in the states in which we offer intrastate transportation services change their policies or aggressively regulate our rates or terms and conditions of service, it could also adversely affect our revenues, including our ability to make cash distributions to our unitholders.

If we lose any of our key personnel, our ability to manage our business and continue our growth could be negatively impacted.

We depend on our senior management team and key technical personnel. If their services are unavailable to us for any reason, we may be required to hire other personnel to manage and operate our company and to develop our products and technology. We cannot assure you that we would be able to locate or employ such qualified personnel on acceptable terms or at all.

Terrorist or cyber-attacks and threats, or escalation of military activity in response to these attacks, could have a material adverse effect on our business, financial condition or results of operations.

Terrorist attacks and threats, cyber-attacks, or escalation of military activity in response to these attacks, may have significant effects on general economic conditions, fluctuations in consumer confidence and spending and market liquidity, each of which could materially and adversely affect our business. Strategic targets, such as energy-related assets and transportation assets, may be at greater risk of future terrorist or cyber-attacks than other targets in the U.S. Due to increased technology advances, we have become more reliant on technology to increase efficiency in our business. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital including our ability to repay or refinance debt. It is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, results of operations, financial condition or cash flows, including our ability to make cash distributions to our unitholders.

We rely heavily on information technology systems for our operations.

The operation of many of our business processes depends on reliable IT systems. We use our Parent's IT systems, which are increasingly dependent on key contractors supporting the delivery of IT services, and continue to expand in terms of number of systems. Shell continuously measures and, where required, further improves its cyber-security capabilities to reduce the likelihood of successful cyber-attacks. Shell's cyber-security capabilities are embedded into its IT systems and its IT landscape is protected by various detective and protective technologies. The identification and assessment capabilities are built into Shell's support processes and adhere to industry best practices. While cyber-security programs and protocols are in place, we cannot guarantee their effectiveness. Disruption of critical IT services, or breaches of information security, could harm our reputation and have a material adverse effect on our business, results of operations, financial condition or cash flows, including our ability to make cash distributions to our unitholders.

Violations of data protection laws carry fines and expose us to criminal sanctions and civil suits.

Data protection laws apply to us and our Parent. For example, the EU GDPR, which came into force in May 2018, increased penalties up to a maximum of 4% of global annual turnover for breach of the regulation. The GDPR requires mandatory breach notification, the standard for which is also followed outside the EU (particularly in Asia). Non-compliance with data protection laws could expose us or our Parent to regulatory investigations, which could result in fines and penalties. In addition to imposing fines, regulators may also issue orders to stop processing personal data, which could disrupt operations. We or our Parent could also be subject to litigation from persons or corporations allegedly affected by data protection violations. Violation of data protection laws is a criminal offense in some countries, and individuals can be imprisoned or fined. Any violation of these laws or harm to our reputation could have a material adverse effect on our business, results of operations, financial condition or cash flows, including our ability to make cash distributions to our unitholders.

Restrictions in our credit facilities could adversely affect our business, financial condition, results of operations, ability to make cash distributions to our unitholders and the value of our units.

We will be dependent upon the earnings and cash flows generated by our operations in order to meet any debt service obligations and to allow us to make cash distributions to our unitholders. We have entered into two revolving credit facilities and two fixed rate facilities, and Zydeco has entered into a senior unsecured revolving credit facility with an affiliate of Shell with a total capacity of $2,990.0 million, under which a total of $2,094.0 million was drawn as of December 31, 2018. Borrowings under our credit facilities were used to fund in part our acquisitions in 2018, 2017 and 2016. Restrictions in our credit facilities and any future financing agreements could restrict our ability to finance our future operations or capital needs or to expand or pursue our business activities, which may, in turn, limit our ability to make cash distributions to our unitholders.

The restrictions in our credit facilities could affect our ability to obtain future financing and pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our credit facilities could result in an event of default which would enable our lenders to declare the outstanding principal of that debt, together with accrued interest, to be immediately due and payable. If the payment of our debt is accelerated, defaults under our other debt instruments, if any, may be triggered, and our assets may be insufficient to repay such debt in full, and the holders of our units could experience a partial or total loss of their investment. See *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Capital Resources and Liquidity — Credit Facilities* in this report for additional information about our credit facilities.

Increases in interest rates could adversely impact the price of our common units, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

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

Our pipeline loss allowance exposes us to commodity risk.

Our long-term transportation agreements and tariffs for crude oil shipments include a pipeline loss allowance. We collect pipeline loss allowance to reduce our exposure to differences in crude oil measurement between origin and destination meters, which can fluctuate widely. This arrangement exposes us to risk of financial loss in some circumstances, including when the crude oil is received from a ship or connecting carrier using different measurement techniques, or resulting from solids and water produced from the crude oil. It is not always possible for us to completely mitigate the measurement differential. If the measurement differential exceeds the loss allowance, the pipeline must make the customer whole for the difference in measured crude oil. Additionally, we take title to any excess product that we transport when product losses are within the allowed levels, and we sell that product several times per year at prevailing market prices. This allowance oil revenue is subject to more volatility than transportation revenue, as it is directly dependent on our measurement capability and prevailing commodity prices.

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

A significant amount of our revenue is generated from assets located in Texas and the Louisiana Gulf Coast and offshore Louisiana. Due to our lack of diversification in assets and geographic location, an adverse development in our businesses or areas of operations, including adverse developments due to catastrophic events, weather, regulatory action and decreases in demand for crude oil and refined products, could have a significantly greater impact on our results of operations and cash available for distribution to our common unitholders than if we maintained more diverse assets and locations.

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

In some cases, our assets include partial ownership interests in joint ventures. If a sufficient amount of our assets, or other assets acquired in the future, are deemed to be "investment securities" within the meaning of the Investment Company Act of 1940, we may have to register as an investment company under the Investment Company Act, claim an exemption, obtain exemptive relief from the SEC or modify our organizational structure or our contract rights. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage, and require us to add additional directors who are independent of us or our affiliates. The occurrence of some or all of these events would adversely affect the price of our common units and could have a material adverse effect on our business, results of operations, financial condition or cash flows, including our ability to make cash distributions to our unitholders.

Risks Inherent in an Investment in Us

Our general partner and its affiliates, including Shell, have conflicts of interest with us and limited duties to us and our unitholders, and they may favor their own interests to the detriment of us and our unitholders. Additionally, we have no control over the business decisions and operations of Shell, and it is under no obligation to adopt a business strategy that favors us.

As of December 31, 2018, SPLC owned a 43.8% limited partner interest in us and owned and controlled our general partner. Although our general partner has a duty to manage us in a manner that is not adverse to the best interests of us and our unitholders, the directors and officers of our general partner also have a duty to manage our general partner in a manner that is not adverse to the best interests of its owner, SPLC. Conflicts of interest may arise between SPLC and its affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts, the general partner may favor its own interests and the interests of its affiliates, including SPLC, over the interests of our common unitholders. These conflicts include, among others, the following situations:

•neither our partnership agreement nor any other agreement requires SPLC to pursue a business strategy that favors us or utilizes our assets, which could involve decisions by SPLC to undertake acquisition opportunities for itself;

•SPLC's directors and officers have a fiduciary duty to make these decisions in the best interests of the owners of SPLC, which may be contrary to our interests; in addition, many of the officers and directors of our general partner are also officers and/or directors of SPLC and will owe fiduciary duties to SPLC and its owners;

•SPLC may be constrained by the terms of its debt instruments from taking actions, or refraining from taking actions, that may be in our best interests;

•our partnership agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties, limiting our general partner’s liabilities and restricting the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;

•except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;
•disputes may arise under agreements pursuant to which SPLC and its affiliates are our customers;
•our general partner will determine the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities and the creation, reduction or increase of cash reserves, each of which can affect the amount of cash that is distributed to our unitholders;
•our general partner will determine the amount and timing of many of our capital expenditures and whether a capital expenditure is classified as an expansion capital expenditure, which would not reduce operating surplus, or a maintenance capital expenditure, which would reduce our operating surplus. This determination can affect the amount of cash that is distributed to our unitholders;
•our general partner will determine which costs incurred by it are reimbursable by us;
•our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions;
•our partnership agreement permits us to classify up to $90.0 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions to our general partner in respect of the general partner units or the incentive distribution rights;
•our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
•our general partner intends to limit its liability regarding our contractual and other obligations;
•our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if it and its affiliates own more than 75.0% of the common units;
•our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates, including under the Omnibus Agreements and our other agreements with SPLC and its affiliates;
•our general partner decides whether to retain separate counsel, accountants or others to perform services for us; and
•our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our general partner's incentive distribution rights without the approval of the conflicts committee of the board of directors of our general partner, which we refer to as our conflicts committee, or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

Under the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including its executive officers, directors and owners. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and our unitholders.

Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.

We expect that we will distribute all of our available cash to our unitholders and will rely primarily upon our cash reserves and external financing sources, including borrowings under our credit facilities and the issuance of debt and equity securities to fund future acquisitions and other expansion capital expenditures. To the extent we are unable to finance growth with external sources of capital, the requirement in our partnership agreement to distribute all of our available cash and our current cash distribution policy will significantly impair our ability to grow. In addition, because we will distribute all of our available cash, our growth may not be as fast as businesses that reinvest all of their available cash to expand ongoing operations.

Our credit facilities restrict our ability to incur additional debt including the issuance of debt securities, except for incurring bank loans or loans from affiliates up to other certain levels. To the extent we issue additional units, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our cash distributions per unit. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to our common units, and our unitholders will have no preemptive or other rights (solely as a result of their status as unitholders) to purchase any such additional units. If we incur additional debt (under our revolving credit facilities or otherwise) to finance our growth strategy, we will have increased interest expense, which in turn will reduce the available cash that we have to distribute to our unitholders.

The fees and reimbursements due to our general partner and its affiliates, including SPLC, for services provided to us or on our behalf will reduce our cash available for distribution. In certain cases, the amount and timing of such reimbursements will be determined by our general partner and its affiliates, including SPLC.

Pursuant to our partnership agreement, we reimburse our general partner and its affiliates, including SPLC, for costs and expenses they incur and payments they make on our behalf. Pursuant to the Omnibus Agreement and our Zydeco operating and management agreement, we pay an annual fee, currently $8.5 million and $8.5 million, respectively, to SPLC for general and administrative services. Effective February 1, 2019, the annual fee increased to $10.5 million pursuant to the new Omnibus Agreement. In addition, pursuant to the Omnibus Agreement, we reimburse our general partner for payments to SPLC for other expenses incurred by SPLC on our behalf to the extent the fees relating to such services are not included in the general and administrative services fee. We also reimburse our general partner and SPLC, as applicable, for certain services provided under our operating agreements related to Pecten, Sand Dollar and Triton West. For the year ended December 31, 2018, we reimbursed our general partner and SPLC $6.1 million and $3.7 million, respectively, under these operating agreements. Each of these payments will be made prior to making any distributions on our common units. The reimbursement of expenses and payment of fees to our general partner and its affiliates will reduce our cash available for distribution. There is no limit on the fee and expense reimbursements that we may be required to pay to our general partner and its affiliates.

Our partnership agreement replaces fiduciary duties applicable to a corporation with contractual duties and restricts the remedies available to holders of our common units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that replace fiduciary duties applicable to a corporation with contractual duties and restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement provides that:

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

•our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as such decisions are made in good faith;

•our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and

•our general partner will not be in breach of its obligations under the partnership agreement (including any duties to us or our unitholders) if a transaction with an affiliate or the resolution of a conflict of interest is:

•approved by the conflicts committee of the board of directors of our general partner, although our general partner is not obligated to seek such approval;

•approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;

•determined by the board of directors of our general partner to be on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

•determined by the board of directors of our general partner to be fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

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

Units held by ineligible holders may be subject to redemption.

We have adopted certain requirements regarding those investors who may own our common units. Eligible taxable holders are limited partners whose, or whose owners', federal income tax status does not have or is not reasonably likely to have a material adverse effect on the rates that can be charged by us on assets that are subject to regulation by FERC or a similar regulatory body, as determined by our general partner with the advice of counsel. Ineligible holders are limited partners (a) who are not an eligible taxable holder or (b) whose nationality, citizenship or other related status would create a substantial risk of cancellation or forfeiture of any property in which we have an interest, as determined by our general partner with the advice of counsel. In certain circumstances set forth in our partnership agreement, units held by an ineligible holder may be redeemed by us at the then-current market price, which is the average of the daily closing prices for the 20 consecutive trading days immediately prior to the redemption date. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner.

Our partnership agreement restricts the voting rights of unitholders owning 20.0% or more of our common units.

Unitholders' voting rights are further restricted by a provision of our partnership agreement providing that any units held by a person that owns 20.0% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot be used to vote on any matter.

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

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. For example, unlike holders of stock in a public corporation, unitholders will not have "say-on-pay" advisory voting rights. Unitholders did not elect our general partner or the board of directors of our general partner and will have no right to elect our general partner or the board of directors of our general partner on an annual or other continuing basis. The board of directors of our general partner is chosen by the member of our general partner, which is a wholly owned subsidiary of SPLC. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. As a result of these limitations, the price at which our common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Even if holders of our common units are dissatisfied, they cannot initially remove our general partner without its consent.

Unitholders will be unable initially to remove our general partner without its consent because our general partner and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least 66 2/3% of all outstanding common units is required to remove our general partner.

Furthermore, unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20.0% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter.

Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

Our general partner interest or the control of our general partner may be transferred to a third party without unitholder consent.
Our partnership agreement does not restrict the ability of SPLC to transfer all or a portion of its general partner interest or its ownership interest in our general partner to a third party. Our general partner, or the new owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own designees and thereby exert significant control over the decisions made by the board of directors and officers.
The incentive distribution rights of our general partner may be transferred to a third party without unitholder consent.
Our general partner may transfer its incentive distribution rights to a third party at any time without the consent of our unitholders. If our general partner transfers its incentive distribution rights to a third party, it will have less incentive to grow our cash flows and increase distributions. A transfer of incentive distribution rights by our general partner could reduce the likelihood of Shell or SPLC selling or contributing additional assets to us, which in turn would impact our ability to grow our asset base.
We may issue additional units without unitholder approval, which would dilute unitholder interests.
At any time, we may issue an unlimited number of limited partner interests of any type without the approval of our unitholders, and our unitholders will have no preemptive or other rights (solely as a result of their status as unitholders) to purchase any such limited partner interests. Further, there are no limitations in our partnership agreement on our ability to issue equity securities that rank equal or senior to our common units as to distributions or in liquidation or that have special voting rights and other rights. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:
•our existing unitholders' proportionate ownership interest in us will decrease;
•the amount of cash we have available to distribute on each unit may decrease;
•because the amount payable to holders of incentive distribution rights is based on a percentage of total available cash, the distributions to holders of incentive distribution rights will increase even if the per unit distribution on common units remains the same;
•the ratio of taxable income to distributions may increase;
•the relative voting strength of each previously outstanding unit may be diminished; and
•the market price of our common units may decline.
SPLC may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.
As of December 31, 2018, SPLC held 99,979,548 common units and no subordinated units. On February 17, 2017, all of the subordinated units converted into common units following the payment of the cash distribution for the fourth quarter of 2016. Additionally, we have agreed to provide SPLC with certain registration rights under applicable securities laws. The sale of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.
Our general partner's discretion in establishing cash reserves may reduce the amount of cash we have available to distribute to unitholders.
Our partnership agreement requires our general partner to deduct from operating surplus the cash reserves that it determines are necessary to fund our future operating expenditures. In addition, the partnership agreement permits the general partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party, or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash we have available to distribute to unitholders.
Our general partner has a limited call right that may require you to sell your common units at an undesirable time or price.
If at any time our general partner and its affiliates own more than 75.0% of our then-outstanding common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less

than all, of the common units held by unaffiliated persons at a price not less than their then-current market price, as calculated pursuant to the terms of our partnership agreement. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. As of December 31, 2018, our general partner and its affiliates owned approximately 44.7% of our common units.

Our general partner, or any transferee holding a majority of the incentive distribution rights, may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to the incentive distribution rights, without the approval of the conflicts committee of our general partner or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

The holder or holders of a majority of the incentive distribution rights, which is initially our general partner, have the right, at any time when the holders have received incentive distributions at the highest level to which they are entitled (48% in addition to distributions paid on its 2% general partner interest) for each of the prior four consecutive fiscal quarters (and the aggregate amounts distributed in respect of such four-quarter period did not exceed adjusted operating surplus for such four-quarter period), to reset the minimum quarterly distribution and the initial target distribution levels at higher levels based on our cash distribution at the time of the exercise of the reset election. Following a reset election, the minimum quarterly distribution will be reset to an amount equal to the average cash distribution per unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the “reset minimum quarterly distribution”), and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution. Our general partner has the right to transfer the incentive distribution rights at any time, in whole or in part, and any transferee holding a majority of the incentive distribution rights shall have the same rights as our general partner with respect to resetting target distributions.

In the event of a reset of the minimum quarterly distribution and the target distribution levels, the holders of the incentive distribution rights will be entitled to receive, in the aggregate, the number of common units equal to that number of common units which would have entitled the holders to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions on the incentive distribution rights in the prior two quarters. Our general partner will also be issued the number of general partner units necessary to maintain the same percentage general partner interest in us that existed immediately prior to the reset election. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal expansion projects that would not otherwise be sufficiently accretive to cash distributions per common unit. It is possible, however, that our general partner or a transferee could exercise this reset election at a time when it is experiencing, or expects to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued common units rather than retain the right to receive incentive distribution payments based on target distribution levels that are less certain to be achieved in the then-current business environment. This risk could be elevated if our incentive distribution rights have been transferred to a third party. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued common units to our general partner in connection with resetting the target distribution levels.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that the counterparties to such arrangements have recourse only against our assets, and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner. Our partnership agreement permits our general partner to limit its liability, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

Our partnership agreement replaces our general partner’s fiduciary duties to holders of our common units with contractual standards governing its duties.

Our partnership agreement contains provisions that eliminate the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law and replace those duties with several different contractual standards. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, free of any duties to us and our unitholders other than the implied contractual covenant of good faith and fair dealing, which means that a court will enforce the reasonable expectations of the partners where the language in the partnership agreement does not provide for a clear course of action. This provision entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

•how to allocate corporate opportunities among us and its other affiliates;
•whether to exercise its limited call right;
•whether to seek approval of the resolution of a conflict of interest by the conflicts committee of the board of directors of our general partner;
•how to exercise its voting rights with respect to the units it owns;
•whether to exercise its registration rights;
•whether to elect to reset target distribution levels;
•whether to transfer the incentive distribution rights to a third party; and
•whether or not to consent to any merger or consolidation of the Partnership or amendment to the partnership agreement.

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

We are required to disclose material changes made in our internal control over financial reporting on a quarterly basis and we are required to assess the effectiveness of our controls annually. An effective system of internal controls is necessary for us to provide reliable and timely financial reports, prevent fraud and to operate successfully as a publicly traded partnership. We prepare our consolidated financial statements in accordance with GAAP, but our internal accounting controls may not meet all standards applicable to companies with publicly traded securities. Our efforts to develop and maintain our system of internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future or to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. For example, Section 404 requires us, among other things, to annually review and report on the effectiveness of our system of internal controls over financial reporting. Any failure to develop, implement or maintain our effective internal controls or the failure to improve our system of internal controls could harm our operating results or cause us to fail to meet our reporting obligations.

We may incur significant costs in our efforts to comply with Section 404. Any failure to implement and maintain an effective system of internal controls over financial reporting will subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business and would likely have a negative effect on the trading price of our common units.

Unitholders' liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. We are organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. A unitholder could be liable for any and all of our obligations as if a unitholder were a general partner if a court or government agency were to determine that (i) we were conducting business in a state but had not complied with that particular state's partnership statute; or (ii) a unitholder's right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

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

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

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

Because we are a publicly traded partnership, the NYSE does not require us to have, and we do not intend to have, a majority of independent directors on our general partner's board of directors or to establish a compensation committee or a nominating and corporate governance committee. Additionally, any future issuance of additional common units or other securities, including to affiliates, will not be subject to the NYSE's shareholder approval rules that apply to a corporation. Accordingly, unitholders will not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements. See *Part III, Item 10. Directors, Executive Officers and Corporate Governance* in this report.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the Internal Revenue Service, or IRS, were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, or if we were otherwise subjected to a material amount of additional entity-level taxation, then our cash available for distribution would be substantially reduced.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. A change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently 21%, and would likely pay state and local income tax at varying rates. Distributions would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions or credits would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution would be substantially reduced. In addition, several states are evaluating changes to current law which could subject us to additional entity-level taxation and further reduce the cash available for distribution to unitholders.

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

The present federal income tax treatment of publicly traded partnerships or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. From time to time, members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. If successful, such a proposal could eliminate the qualifying income exception to the treatment of all publicly-traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted or will materially change interpretations of the current law, but it is possible that a change in law could affect us and may, if enacted, be applied retroactively. Any such changes would have a material adverse effect on our financial condition, cash flows, ability to make cash distributions to our unitholders and the value of an investment in our common units.

Our unitholders are required to pay income taxes on their share of our taxable income even if they do not receive any cash distributions from us. A unitholder's share of our taxable income, and its relationship to any distributions we make, may be affected by a variety of factors, including our economic performance, transactions in which we engage or changes in law and may be substantially different from any estimate we make in connection with a unit offering.

A unitholders' allocable share of our taxable income will be taxable to it, which may require the unitholder to pay federal income taxes and, in some cases, state and local income taxes, even if the unitholder receives cash distributions from us that are less than the actual tax liability that results from that income or no cash distribution at all.

A unitholders’ share of our taxable income, and its relationship to any distributions we make, may be affected by a variety of factors, including our economic performance, which may be affected by numerous business, economic, regulatory, legislative, competitive and political uncertainties beyond our control, and certain transactions in which we might engage. For example, we may engage in transactions that produce substantial taxable income allocations to some or all of our unitholders without a corresponding increase in cash distributions to our unitholders, such as a sale or exchange of assets, the proceeds of which are reinvested in our business or used to reduce our debt, or an actual or deemed satisfaction of our indebtedness for an amount less than the adjusted issue price of the debt. A unitholders' ratio of its share of taxable income to the cash received by it may also be affected by changes in law. For instance, our net interest rate deductions under the TCJA are limited to 30% of our "adjusted taxable income," which is generally taxable income with certain modifications. If the limit applies, a unitholders' taxable income allocations will be more (or its net loss allocations will be less) than would have been the case absent the limitation.

From time to time, in connection with an offering of our units, we may state an estimate of the ratio of federal taxable income to cash distributions that a purchaser of units in that offering may receive in a given period. These estimates depend in part on factors that are unique to the offering with respect to which the estimate is stated, so the expected ratio applicable to other units will be different, and in many cases less favorable, than these estimates. Moreover, even in the case of units purchased in the offering to which the estimate relates, the estimate may be incorrect, due to the uncertainties described above, challenges by the IRS to tax reporting positions which we adopt, or other factors. The actual ratio of taxable income to cash distributions could be higher or lower than expected, and any differences could be material and could materially affect the value of the common units.

***If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution*.**

Any contest with the IRS, and the outcome of any IRS contest, may have a materially adverse impact on the market for our common units and the price at which our common units trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, under the TCJA, for taxable years beginning after December 31, 2017, our deduction for "business interest" is limited to the sum of our business interest income and 30% of our "adjusted taxable income." For purposes of this limitation, our adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion.

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

If our unitholders sell common units, the unitholders will recognize a gain or loss for federal income tax purposes equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of a unitholder's allocable share of our net taxable income decrease the unitholder's tax basis in its common units, the amount, if any, of such prior excess distributions with respect to the common units a unitholder sells will, in effect, become taxable income to the unitholder if it sells such common units at a price greater than its tax basis in those common units, even if the price received is less than its original cost. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, a unitholder that sells common units may incur a tax liability in excess of the amount of cash received from the sale.

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

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income ("UBTI") and will be taxable to them. Under the TCJA, an exempt organization is required to independently compute its UBTI from each separate unrelated trade or business which may prevent an exempt organization from utilizing losses we allocate to the organization against the organization's UBTI from other sources and vice versa. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file federal income tax returns and applicable state tax returns and pay tax on their share of our taxable income.

Under the TCJA, if a unitholder sells or otherwise disposes of a common unit, the transferee is required to withhold 10.0% of the amount realized by the transferor unless the transferor certifies that it is not a foreign person, and we are required to deduct and withhold from the transferee amounts that should have been withheld by the transferee but were not withheld. However, the U.S. Department of the Treasury and the IRS have determined that this withholding requirement should not apply to any disposition of a publicly traded interest in a publicly traded partnership (such as us) until regulations or other guidance have been issued clarifying the application of this withholding requirement to dispositions of interests in publicly traded partnerships. Accordingly, while this new withholding requirement does not currently apply to interests in us, there can be no assurance that such requirement will not apply in the future.

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

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

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

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The U.S. Department of the Treasury adopted final Treasury Regulations allowing a similar monthly simplifying convention for taxable years beginning on or after August 3, 2015. However, such final regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it (and some states) may collect any resulting taxes (including any applicable penalties and interest) directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, if the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us. We will generally have the ability to shift any such tax liability to our general partner and our unitholders in accordance with their interests in us during the year under audit, but there can be no assurance that we will be able to do so (and will choose to do so) under all circumstances, or that we will be able to (or choose to) effect corresponding shifts in state income or similar tax liability resulting from the IRS adjustment in states in which we do business in the year under audit or in the adjustment year. If we make payments of taxes, penalties and interest resulting from audit adjustments, our cash available for distribution to our unitholders might be substantially reduced. Additionally, we may be required to allocate an adjustment disproportionately among our unitholders, causing the publicly traded units to have different capital accounts, unless the IRS issues further guidance.

In the event the IRS makes an audit adjustment to our income tax returns and we do not or cannot shift the liability to our unitholders in accordance with their interests in us during the year under audit, we will generally have the ability to request that the IRS reduce the determined underpayment by reducing the suspended passive loss carryovers of our unitholders (without any compensation from us to such unitholders), to the extent such underpayment is attributable to a net decrease in passive activity losses allocable to certain partners. Such reduction, if approved by the IRS, will be binding on any affected unitholders.

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

Because a unitholder whose common units are loaned to a "short seller" to effect a short sale of common units may be considered as having disposed of the loaned common units, the unitholder may no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income.

We have adopted certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methodologies, which could adversely affect the value of the common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. The IRS may challenge our valuation methods and allocations of taxable income, gain, loss and deduction between our general partner and certain of our unitholders.

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

If our assets were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our cash available for distribution to our unitholders.

If our assets are subjected to a material amount of additional entity-level taxation by individual states, our cash available for a distribution would be reduced. States are continually evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. We currently own assets and conduct business in certain states which impose an entity-level tax on partnerships, including Illinois, Texas, and Washington. Imposition of an entity-level tax on us in other jurisdictions in which we do business, or to which we expand our operations, could substantially reduce our cash available for distribution. Our partnership agreement provides that, if a law is enacted or an existing law is modified or interpreted in a manner that subjects us to entity-level taxation, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

As a result of investing in our common units, unitholders will likely be subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire properties.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or control property now or in the future. Unitholders may be subject to such taxes, even if they do not live in the jurisdiction imposing the tax. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own property and conduct business in a number of states, most of which currently impose a personal income tax on individuals, and most of which also impose an income or similar tax on corporations and certain other entities. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose an income tax or similar tax. In certain states, tax losses may not produce a tax benefit in the year incurred and also may not be available to offset income in subsequent tax years. Some states may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be greater or less than a particular unitholders' income tax liability to the state, generally does not relieve a nonresident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us. It is each unitholder's responsibility to file all federal, state and local tax returns required by applicable law to be filed by such unitholder. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in our common units. Prospective unitholders should consult their own tax advisors regarding such matters.

Entity level taxes on income from C corporation subsidiaries will reduce cash available for distribution, and an individual unitholder's share of dividend and interest income from such subsidiaries would constitute portfolio income that could not be offset by the unitholder's share of our other losses or deductions.

A portion of our taxable income is earned through LOCAP, Explorer and Colonial, which are all C corporations. Such C corporations are subject to federal income tax on their taxable income at the corporate tax rate, which is currently 21.0%, and will likely pay state (and possibly local) income tax at varying rates, on their taxable income. Any such entity level taxes will reduce the cash available for distribution to our unitholders. Distributions from any such C corporation will generally be taxed again to unitholders as dividend income to the extent of current and accumulated earnings and profits of such C corporation. As of December 31, 2018, the maximum federal income tax rate applicable to such qualified dividend income that is allocable to individuals was 20.0%. An individual unitholders' share of dividend and interest income from LOCAP, Explorer, Colonial or other C corporation subsidiaries would constitute portfolio income that could not be offset by the unitholders' share of our other losses or deductions.

Item 1B. UNRESOLVED STAFF COMMENTS

None.

Item 3. LEGAL PROCEEDINGS

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the ordinary course of business, we are not a party to any litigation or governmental or other proceeding that we believe will have a material adverse impact on our financial position, results of operations, or cash flows. In addition, pursuant to the terms of the various agreements under which we acquired assets from Shell affiliates since the IPO, those affiliates, as applicable, will indemnify us for certain liabilities relating to litigation and environmental matters attributable to the ownership or operation of the acquired assets prior to our acquisition of those assets.

Effective July 31, 2014, a rate case was filed against Zydeco with FERC. The rate case was resolved by a settlement approved by FERC which established maximum rates for uncommitted (or non-contract) shippers effective December 1, 2015. The settlement also provided for rate refunds for shippers of the difference between the higher pre-settlement uncommitted (or non-contract) rates and the lower settlement rates for the period from July 31, 2014 to November 30, 2015 (plus interest). In 2015, we recognized $2.3 million of general and administrative expenses related to the settlement of this rate case, and the shippers' settlements were paid in January 2016. We filed claims for reimbursement of $1.4 million in 2015 from SPLC, and we received reimbursement in 2016. On a prospective basis, a successful challenge of any of our rates, or any changes to FERC's approved rate or index methodologies, could adversely affect our revenue and cash flows, including our ability to make distributions to our unitholders.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Quarterly Common Unit Prices and Cash Distributions Per Unit

Our common units trade on the NYSE under the symbol "SHLX."

As of February 21, 2019, SPLC owned 99,979,548 common units, representing an aggregate 43.8% limited partner interest in us, all of the incentive distribution rights, and 4,567,588 general partner units, representing a 2% general partner interest in us. On February 15, 2017, all of the subordinated units converted into common units following the payment of the cash distribution for the fourth quarter of 2016. As of February 1, 2019, we had four holders of record of our common units. In determining the number of unitholders, we consider clearing agencies and security position listings as one unitholder for each agency or listing.

Distributions of Available Cash

General

Our partnership agreement requires us to distribute all of our available cash to unitholders of record on the applicable record date, within 60 days after the end of each quarter.

Definition of Available Cash

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

•*less*, the amount of cash reserves established by our general partner to:

•provide for the proper conduct of our business (including reserves for our future maintenance and expansion capital expenditures, future acquisitions and anticipated future debt service requirements and refunds of collected rates reasonably likely to be refunded as a result of a settlement or hearing related to FERC rate proceedings or rate proceedings under applicable law) subsequent to that quarter;

•comply with applicable law, any of our or our subsidiaries' debt instruments or other agreements; or

•provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters (provided that our general partner may not establish cash reserves for distributions if the effect of the establishment of such reserves will prevent us from making the minimum quarterly distribution on all common units and any cumulative arrearages on such common units for the current quarter);

•*plus*, all cash on hand on the date of determination resulting from dividends or distributions received after the end of the quarter from equity interests in any person other than a subsidiary in respect of operations conducted by such person during the quarter;

•*plus*, if our general partner so determines, all or any portion of the cash on hand on the date of determination resulting from working capital borrowings after the end of the quarter.

The purpose and effect of the last bullet point above is to allow our general partner, if it so decides, to use cash from working capital borrowings made after the end of the quarter but on or before the date of determination of available cash for that quarter to pay distributions to unitholders. Under our partnership agreement, working capital borrowings are generally borrowings that are made under a credit facility, commercial paper facility or similar financing arrangement, and in all cases are used solely for working capital purposes or to pay distributions to partners, and with the intent of the borrower to repay such borrowings within twelve months with funds other than from additional working capital borrowings.

Intent to Distribute the Minimum Quarterly Distribution

We intend to make at least the minimum quarterly distribution of $0.1625 per unit, or $0.6500 per unit on an annualized basis, to the holders of our units to the extent we have sufficient available cash after the establishment of cash reserves and the payment of costs and expenses, including reimbursements of expenses to our general partner. However, there is no guarantee that we will pay the minimum quarterly distribution or any amount on our units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions we pay and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement. See *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and*

Results of Operations — Capital Resources and Liquidity — Credit
48

Facilities in this report, for a discussion of the restrictions included in our credit facilities that may restrict our ability to make distributions.

General Partner Interest and Incentive Distribution Rights

Our general partner is currently entitled to 2% of all quarterly distributions. This general partner interest is represented by 4,567,588 general partner units as of February 21, 2019. Our general partner has the right, but not the obligation, to contribute up to a proportionate amount of capital to us to maintain its current general partner interest upon the issuance of additional units. The general partner's initial 2% interest in these distributions will be reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest.

Our general partner also currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 48.0%, of the cash we distribute from operating surplus (as defined in our partnership agreement) in excess of $0.186875 per unit per quarter. The maximum distribution of 48.0% does not include any distributions that our general partner or its affiliates may receive on common or general partner units that they own.

On December 21, 2018, we and our general partner executed Amendment No. 2 (the "Second Amendment") to the Partnership's First Amended and Restated Agreement of Limited Partnership dated November 3, 2014. Under the Second Amendment, our sponsor agreed to waive $50.0 million of distributions in 2019 by agreeing to reduce distributions to holders of the incentive distribution rights by: (1) $17.0 million for the quarter ending March 31, 2019, (2) $17.0 million for the quarter ending June 30, 2019 and (3) $16.0 million for the quarter ending September 30, 2019.

Percentage Allocations of Available Cash from Operating Surplus

The following table illustrates the percentage allocations of available cash from operating surplus between the unitholders and our general partner based on the specified target distribution levels. The amounts set forth under *Marginal Percentage Interest in Distributions* are the percentage interests of our general partner and the unitholders in any available cash from operating surplus we distribute up to and including the corresponding amount in the column *Target Quarterly Distribution per Unit Target Amount*. The percentage interests shown for our unitholders and our general partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our general partner include its 2% general partner interest and assume that our general partner has contributed any additional capital necessary to maintain its 2% general partner interest, our general partner has not transferred its incentive distribution rights and that there are no arrearages on common units.

	Target Quarterly Distribution per Unit Target Amount		**Marginal Percentage Interest in Distributions** **LP Unitholders**	**General Partner**
Minimum Quarterly Distribution	$ 0.162500		98%	2%
First Target Distribution	above $ 0.162500	up to $ 0.186875	98%	2%
Second Target Distribution	above $ 0.186875	up to $ 0.203125	85%	15%
Third Target Distribution	above $ 0.203125	up to $ 0.243750	75%	25%
Thereafter			50%	50%

above
$
0.243750

Expiration of Subordination Period

On February 15, 2017, all of the subordinated units converted into common units following the payment of the cash distribution for the fourth quarter of 2016. Each of our 67,475,068 outstanding subordinated units converted into one common unit. As of March 31, 2017, and for any distribution of available cash in subsequent periods, the converted units participate pro rata with the other common units in distributions of available cash. The conversion of the subordinated units does not impact the amount of cash distributions paid by us or the total number of outstanding units. The allocation of net income and cash distributions during the period were effected in accordance with terms of the partnership agreement.

Equity Compensation Plan

The information relating to our equity compensation plan required by Item 5 is incorporated by reference to such information as set forth in *Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters* of this report.

Item 6. SELECTED FINANCIAL DATA

Please read the selected financial data presented below in conjunction with *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* and the consolidated financial statements and accompanying notes included in *Part II, Item 8* of this report.

(in millions of dollars, except per unit data)	**2018**		**2017**		**2016**		**2015**		**2014**	
Statements of Income										
Total revenue (1)	$	524.7	$	470.1	$	452.9	$	485.5	$	379.4
Total costs and expenses (1)	312.5		270.0		229.4		232.9		204.8	
Operating income	212.2		200.1		223.5		252.6		174.6	
Investment, dividend and other income (loss)	333.1		224.0		166.3		125.6		40.9	
Net income	482.4		391.8		377.5		374.0		215.0	
Net income attributable to the Partnership	464.1		295.3		244.9		167.1		13.4	
Net income per Limited Partner Unit - Basic and Diluted:										
Common	$	1.50	$	1.28	$	1.32	$	1.16	$	0.10
Subordinated	$	—	$	—	$	1.27	$	1.14	$	0.10
Cash distributions declared per limited partner unit (2)	$	1.4950	$	1.2461	$	1.0258	$	0.7900	$	0.1042
Balance Sheets										
Property, plant and equipment, net	$	742.4	$	736.5	$	733.7	$	731.3	$	616.3
Total assets	$	1,913.5	$	1,366.5	$	1,303.9	$	1,164.7	$	1,071.8
Debt payable – related party	$	2,090.7	$	1,844.0	$	686.0	$	457.6	$	—

Lease liability [3]	$	25.1	$	24.3	$	24.9	$	22.8	$	—
Total (deficit) equity	$	(257.0)	$	(565.9)	$	534.2	$	632.8	$	989.4

(1) As a result of the adoption of the new revenue standard, prior period amounts have not been adjusted under the modified retrospective method and continue to be reported in accordance with our historic accounting under previous GAAP.
(2) The 2014 distribution per limited partner unit represents the pro-rated minimum quarterly distribution for the 59-day period from November 3, 2014 to December 31, 2014 in accordance with the Partnership Agreement.
(3) As part of the Motiva JV separation effective May 2017, Motiva is no longer a related party. As of both December 31, 2018 and 2017, this is a third-party balance.

50

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations
Management's Discussion and Analysis of Financial Condition and Results of Operations are the analysis of our financial performance, financial condition, and significant trends that may affect future performance. It should be read in conjunction with the consolidated financial statements and notes thereto included in Part II, Item 8 of this report. It should also be read together with "Risk factors" and "Cautionary Statement Regarding Forward-Looking Statements" in this report.

On January 1, 2018, we adopted Topic 606, Revenue from Contracts with Customers, and all related ASU's to this Topic (collectively, "the new revenue standard") by applying the modified retrospective method to all contracts that were not completed on January 1, 2018. Results for reporting periods beginning after January 1, 2018 are presented in accordance with the new revenue standard, while prior period amounts are not adjusted and continue to be reported in accordance with our historic accounting under previous GAAP. See Note 3 – Revenue Recognition in the Notes to Consolidated Financial Statements included in Part II, Item 8.
Partnership Overview
We are a growth-oriented master limited partnership that owns, operates, develops and acquires pipelines and other midstream assets. As of December 31, 2018, our assets include interests in entities that own crude oil and refined products pipelines and terminals that serve as key infrastructure to (i) transport onshore and offshore crude oil production to Gulf Coast and Midwest refining markets and (ii) deliver refined products from those markets to major demand centers. Our assets also include interests in entities that own natural gas and refinery gas pipelines which transport offshore natural gas to market hubs and deliver refinery gas from refineries and plants to chemical sites along the Gulf Coast.
For a description of our assets, please see *Part I, Item 1 - Business and Properties* of this report.
2018 developments include:
•*IDR Waiver*. On December 21, 2018, we and our general partner executed Amendment No. 2 (the "Second Amendment") to our Partnership Agreement. Under the Second Amendment, our sponsor agreed to waive $50.0 million of distributions in 2019 by agreeing to reduce distributions to holders of the incentive distribution rights by: (1) $17.0 million for the quarter ending March 31, 2019, (2) $17.0 million for the quarter ending June 30, 2019 and (3) $16.0 million for the quarter ending September 30, 2019. We intend to use these funds for future investment.
•*Borrowings.* On July 31, 2018, we entered into a seven-year fixed rate credit facility with Shell Treasury Center (West) Inc. ("STCW") with a borrowing capacity of $600.0 million (the "Seven Year Fixed Facility"). Additionally, on August 1, 2018, we amended and restated the Five Year Revolving Credit Facility due October 2019 such that the facility will now mature on July 31, 2023 (the "Five Year Credit Facility due July 2023").
•*May 2018 Acquisition.* In May 2018, we entered into a purchase and sale agreement (the "Purchase Agreement") with SPLC to acquire SPLC's ownership interests in Amberjack Pipeline Company LLC, a Delaware limited liability company ("Amberjack"), which is comprised of 75% of the issued and outstanding Series A membership interests of Amberjack and 50% of the issued and outstanding Series B membership interests of Amberjack for $1,220.0 million (the "May 2018 Acquisition"). Amberjack is a joint venture with Chevron Pipe Line Company and owns an approximately 360-mile pipeline system in the Gulf of Mexico. We completed the May 2018 Acquisition in the second quarter of 2018 pursuant to the terms of the Purchase Agreement in exchange for payment to SPLC of $1,220.0 million in cash, which we funded with borrowings under existing credit facilities.
•*Equity Offerings.* In February 2018, we completed the sale of 25,000,000 common units in a registered public offering for $673.3 million net proceeds, and the sale of 11,029,412 common units in a private placement with Shell Midstream LP Holdings LLC, an indirect subsidiary of Shell, for an aggregate purchase price of $300.0 million.
•*Debt Repayments.* In February 2018, we used net proceeds from sales of common units and from our general partner's proportionate capital contribution to repay $246.9 million of borrowings outstanding under the Five Year Revolver due July 2023 and $726.0 million of borrowings outstanding under the Five Year Revolver due December 2022. Refer to *Note 9 – Related Party Debt* in the *Notes to Consolidated Financial Statements* included in *Part II, Item 8* for definitions.

We generate revenue from the transportation, terminaling and storage of crude oil and refined products through our pipelines and storage tanks, and we generate income from our equity and other investments. Our revenue is generated from customers in the same industry, our Parent’s affiliates, integrated oil companies, marketers, and independent exploration, production and refining companies primarily within the Gulf Coast region of the U.S. We generally do not own any of the crude oil, refinery gas or refined petroleum products we handle, nor do we engage in the trading of these commodities. We therefore have limited direct exposure to risks associated with fluctuating commodity prices, although these risks indirectly influence our activities and results of operations over the long-term.

As a result of outages and repairs in 2017 related to Hurricane Harvey across several of our assets, as well as the declaration of a force majeure event for Zydeco, we incurred an impact of approximately $10.5 million in 2017 and $0.5 million in the first quarter of 2018 to net income and cash available for distribution. Because we declared a force majeure event for Zydeco, the expiration of unused credits on our committed transportation agreements for months prior to September 2017 has been extended one month. Refer to "*Critical Accounting Policies and Estimates - Revenue Recognition*" for additional information on these agreements.

As a result of Hurricane Michael in October 2018, we incurred an impact of approximately $2.5 million to net income and cash available for distribution in the fourth quarter of 2018. Although SPLC operated assets did not shut down, most platforms connected to assets in the eastern corridor of the Gulf of Mexico elected to shut in and evacuate as a safety precaution. There was no impact to people, assets or the environment in the corridor.

Executive Overview

Net income was $482.4 million and net income attributable to the Partnership was $464.1 million in 2018. We generated cash from operations of $508.4 million, raised $973.3 million in net proceeds from the sales of common units and increased our borrowing capacity by $600.0 million. Cash generated was primarily used to pay down debt with STCW. In addition, we completed the May 2018 Acquisition for $1,220.0 million. As of December 31, 2018, we had cash and cash equivalents of $208.0 million, total debt of $2,090.7 million, and unused capacity under our revolving credit facilities of $896.0 million.

Our 2018 operations and strategic initiatives demonstrated our continuing focus on our business strategies:

- Maintain operational excellence through prioritization of safety, reliability and efficiency;
- Growth through strategic acquisitions in key geographies to achieve integrated value;
- Focus on advantageous commercial agreements with creditworthy counterparties to enhance financial results and deliver reliable distribution growth over the long-term; and
- Optimize existing assets and pursue organic growth opportunities.

How We Evaluate Our Operations

Our management uses a variety of financial and operating metrics to analyze our performance. These metrics are significant factors in assessing our operating results and profitability and include: (i) revenue (including pipeline loss allowance ("PLA") from contracted capacity and throughput; (ii) operations and maintenance expenses (including capital expenses); (iii) Adjusted EBITDA (defined below); and (iv) Cash Available for Distribution.

Contracted Capacity and Throughput

The amount of revenue our assets generate primarily depends on our transportation and storage services agreements with shippers and the volumes of crude oil, refinery gas and refined products that we handle through our pipelines, terminals and storage tanks.

The commitments under our transportation, terminaling and storage services agreements with shippers and the volumes which we handle in our pipelines and storage tanks are primarily affected by the supply of, and demand for, crude oil, refinery gas, natural gas and refined products in the markets served directly or indirectly by our assets. This supply and demand is impacted by the market prices for these products in the markets we serve. We utilize the commercial arrangements we believe are the most prudent under the market conditions to deliver on our business strategy. The results of our operations will be impacted by our ability to:

- maintain utilization of and rates charged for our pipelines and storage facilities;

- utilize the remaining uncommitted capacity on, or add additional capacity to, our pipeline systems;

•increase throughput volumes on our pipeline systems by making connections to existing or new third party pipelines or other facilities, primarily driven by the anticipated supply of, and demand for, crude oil and refined products; and

•identify and execute organic expansion projects.

Operations and Maintenance Expenses

Our management seeks to maximize our profitability by effectively managing operations and maintenance expenses. These expenses are comprised primarily of labor expenses (including contractor services), insurance costs (including coverage for our consolidated assets and operated joint ventures), utility costs (including electricity and fuel) and repairs and maintenance expenses. Utility costs fluctuate based on throughput volumes and the grades of crude oil and types of refined products we handle. Management performed a strategic evaluation of its insurance coverage and since renewal of the contracts at the end of 2017, all of our property and business interruption coverage is provided by a wholly owned subsidiary of Shell. This resulted in both overall cost savings and improved coverage. Our other operations and maintenance expenses generally remain stable across broad ranges of throughput and storage volumes, but can fluctuate from period to period depending on the mix of activities, particularly maintenance activities, performed during a period. At times, the fluctuation in operations and maintenance expenses may materially increase due to the performance of planned maintenance, such as turnaround work and asset integrity work, and unplanned maintenance, such as repair of damage caused by a natural disaster.

Adjusted EBITDA and Cash Available for Distribution

Adjusted EBITDA and cash available for distribution have important limitations as analytical tools because they exclude some, but not all, items that affect net income and net cash provided by operating activities. You should not consider Adjusted EBITDA or cash available for distribution in isolation or as a substitute for analysis of our results as reported under GAAP. Additionally, because Adjusted EBITDA and cash available for distribution may be defined differently by other companies in our industry, our definition of Adjusted EBITDA and cash available for distribution may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

The GAAP measures most directly comparable to Adjusted EBITDA and cash available for distribution are net income and net cash provided by operating activities. Adjusted EBITDA and cash available for distribution should not be considered as an alternative to GAAP net income or net cash provided by operating activities. Please refer to "*Results of Operations -Reconciliation of Non-GAAP Measures*" for the reconciliation of GAAP measures net income and cash provided by operating activities to non-GAAP measures Adjusted EBITDA and cash available for distribution.

We define Adjusted EBITDA as net income before income taxes, net interest expense, gain or loss from dispositions of fixed assets, allowance oil reduction to net realizable value, and depreciation, amortization and accretion, *plus* cash distributed to us from equity investments for the applicable period, *less* income from equity investments. We define Adjusted EBITDA attributable to the Partnership as Adjusted EBITDA less Adjusted EBITDA attributable to noncontrolling interests and Adjusted EBITDA attributable to Parent.

We define cash available for distribution as Adjusted EBITDA attributable to the Partnership less maintenance capital expenditures attributable to the Partnership, net interest paid, cash reserves and income taxes paid, plus net adjustments from volume deficiency payments attributable to the Partnership and certain one-time payments received. Cash available for distribution will not reflect changes in working capital balances.

We believe that the presentation of these non-GAAP supplemental financial measures provides useful information to management and investors in assessing our financial condition and results of operations. We present these financial measures because we believe replacing our proportionate share of our equity investments' net income with the cash received from such equity investments more accurately reflects the cash flow from our business, which is meaningful to our investors.

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

•our operating performance as compared to other publicly traded partnerships in the midstream energy industry, without regard to historical cost basis or, in the case of Adjusted EBITDA, financing methods;

•the ability of our business to generate sufficient cash to support our decision to make distributions to our unitholders;

•our ability to incur and service debt and fund capital expenditures; and

•the viability of acquisitions and other capital expenditure projects and the returns on investment of various investment opportunities.

Factors Affecting Our Business and Outlook

We believe key factors that impact our business are the supply of, and demand for, crude oil, natural gas, refinery gas and refined products in the markets in which our business operates. We also believe that our customers’ requirements, competition and government regulation of crude oil, refined products, natural gas and refinery gas play an important role in how we manage our operations and implement our long-term strategies. In addition, acquisition opportunities, whether from Shell or third parties, and financing options, will also impact our business. These factors are discussed in more detail below.

Changes in Crude Oil Sourcing and Refined Product Demand Dynamics

To effectively manage our business, we monitor our market areas for both short-term and long-term shifts in crude oil and refined products supply and demand. Changes in crude oil supply such as new discoveries of reserves, declining production in older fields, operational impacts at producer fields and the introduction of new sources of crude oil supply, affect the demand for our services from both producers and consumers. One of the strategic advantages of our crude oil pipeline systems is their ability to transport attractively priced crude oil from multiple supply markets to key refining centers along the Gulf Coast. Our crude oil shippers periodically change the relative mix of crude oil grades delivered to the refineries and markets served by our pipelines. They also occasionally choose to store crude longer term when the forward price is higher than the current price (a “contango market”). While these changes in the sourcing patterns of crude oil transported or stored are reflected in changes in the relative volumes of crude oil by type handled by our pipelines, our total crude oil transportation revenue is primarily affected by changes in overall crude oil supply and demand dynamics and U.S. exports.

Similarly, our refined products pipelines have the ability to serve multiple major demand centers. Our refined products shippers periodically change the relative mix of refined products shipped on our refined products pipelines, as well as the destination points, based on changes in pricing and demand dynamics. While these changes in shipping patterns are reflected in relative types of refined products handled by our various pipelines, our total product transportation revenue is primarily affected by changes in overall refined products supply and demand dynamics. Demand can also be greatly affected by refinery performance in the end market, as refined products pipeline demand will increase to fill the supply gap created by refinery issues.

We can also be constrained by asset integrity considerations in the volumes we ship. We may elect to reduce cycling on our systems to reduce asset integrity risk, which in turn would likely result in lower revenues.

As these supply and demand dynamics shift, we anticipate that we will continue to actively pursue projects that link new sources of supply to producers and consumers. Similarly, as demand dynamics change, we anticipate that we will create new services or capacity arrangements that meet customer requirements. We expect to continue extending our corridor pipelines to provide developing growth regions in the Gulf of Mexico with access via our existing corridors to onshore refining centers and market hubs. For example, Stampede achieved first oil in January 2018, and Big Foot and Claiborne came online at the end of 2018. We believe this strategy will allow our offshore business to grow profitably throughout demand cycles.

Changes in Customer Contracting

We generate a portion of our revenue under long-term transportation service agreements with shippers, including ship-or-pay agreements and life-of-lease transportation agreements, some of which provide a guaranteed return, and storage service agreements with marketers, pipelines and refiners. Historically, the commercial terms of these long-term transportation and storage service agreements have substantially mitigated volatility in our financial results by limiting our direct exposure to reductions in volumes due to supply or demand variability. Our business could be negatively affected if we are unable to renew or replace our contract portfolio on comparable terms, by sustained downturns or sluggishness in commodity prices or the economy in general, and is impacted by shifts in supply and demand dynamics, the mix of services requested by the customers of our pipelines, competition and changes in regulatory requirements affecting our operations. Our business can also be impacted by asset integrity or customer interruptions and natural disasters.

Two of our long-term transportation services agreements on the Zydeco system expired at the end of 2018, and another will expire in the second quarter of 2019. These contracts represented approximately 30% of our revenues for both the years ended December 31, 2018 and 2017. If we are not able to re-contract these volumes, or if the rates are substantially lower than those previously contracted, net income and cash available for distribution will be negatively impacted. Prolonged lower rates and the length of time without contracts could have a material impact on our financial results.

The market environment will dictate the rates, terms and lengths of any new agreements. Increases or decreases in available crude supply in the Houston market could affect demand for transportation to other markets, especially the Louisiana refining market. A number of factors could impact this, including increased production in fields with Houston connectivity and increased export capabilities at Texas Gulf Coast ports. Further, shippers may choose alternate routes on which to ship. Alternatively, Louisiana refineries' availability and crude slates, as well as potential crude options at Louisiana Gulf Coast ports, could impact Louisiana demand for crude types available in the Houston market. Additionally, crude prices and basis differentials will directly impact the price our customers are willing to pay to transport.

As we continue discussions with new and existing shippers and monitor the market factors above, we will run the system with spot shipments at the posted tariff rates for our non-contracted capacity. Based on recent demand levels on the system, we believe that Zydeco continues to serve an important market and although the current market supports the use of spot shipments, we continue to strive for long-term agreements which provide more ratable financial results.

Additionally, revenue we generate from spot shipments will typically have a corresponding positive impact on cash available for distribution. However, in the first half of 2019, previously committed shippers will have the ability to ship on credits earned related to under-shipments prior to the expiration of their contracts. As such, we will recognize revenue for the usage of those credits, but we will not receive cash. We expect that the majority of these credits will be utilized in the first quarter.

The cumulative effect of the foregoing circumstances and challenges would have a material impact on our financial results. We expect the impact on our net income and cash available for distribution in the first quarter of 2019 to each be in the range of $15.0 million to $25.0 million. However, the aforementioned factors are constantly evolving and as such may not be a reliable predictor of actual financial results.

Changes in Commodity Prices and Customers' Volumes

Crude oil prices have fluctuated significantly over the past few years, often with drastic moves in relatively short periods of time. During 2018, prices slowly increased from 2017 levels until the middle of the fourth quarter, at which point there was a steep decline. The current global geopolitical and economic uncertainty continues to contribute to volatility in financial and commodity markets. Our direct exposure to commodity price fluctuations is limited to the PLA provisions in our tariffs. We have indirect exposure to commodity price fluctuations to the extent such fluctuations affect the shipping patterns of our customers. Our assets benefit from long-term fee-based arrangements, and are strategically positioned to connect crude oil volumes originating from key onshore and offshore production basins to the Texas and Louisiana refining markets, where demand for throughput has remained strong. Historically, we have not experienced a material decline in throughput volumes on our crude oil pipeline systems as a result of lower crude oil prices. However, if crude oil prices remain at lower levels for a sustained period, we could see a reduction in our transportation volumes if production coming into our systems is deferred and our associated allowance oil sales decrease. Our customers may also experience liquidity and credit problems, which could cause them to defer development or repair projects, avoid our contracts in bankruptcy, or renegotiate our contracts on terms that are less attractive to us or impair their ability to perform under our contracts.

Our throughput volumes on our refined products pipeline systems depend primarily on the volume of refined products produced at connected refineries and the desirability of our end markets. These factors in turn are driven by refining margins, maintenance schedules and market differentials. Refining margins depend on the cost of crude oil or other feedstocks and the price of refined products. These margins are affected by numerous factors beyond our control, including the domestic and global supply of and demand for crude oil and refined products. We are currently experiencing relatively high demand for our pipeline systems that service refineries.

Other Changes in Customers' Volumes

Total Zydeco volumes were lower in 2018 versus 2017 primarily due to a Force Majeure declared due to the hydro-test of the Zydeco pipeline from Houston, Texas to Houma, Louisiana resulting in 49 days of downtime in

2018. Additionally, there was a sale of an interplant line delivering to a connecting refinery during 2017, which resulted in lower volume in 2018. These decreases were partially offset by an increase in barrels originating from Houston and Nederland, as well as higher deliveries from Poseidon in 2018.
Transportation volumes on Auger were lower in 2018 versus 2017 primarily due to the shut-in of production throughout the first half of 2018 at certain connected producer facilities caused by the fire at the Enchilada platform in the fourth quarter of 2017.

Transportation volumes on Na Kika were slightly higher in 2018 versus 2017 driven by the new Coulomb redevelopment wells which achieved first oil in March 2018. Odyssey volumes were relatively flat in 2018 versus 2017. Despite higher volumes from select platforms in 2018 due to tie-backs, the new fields did not offset the impact of multiple legacy fields being shut-in for unplanned maintenance during the first half of 2018. These legacy fields returned to service early in the third quarter of 2018. Delta experienced increased transportation volumes in 2018 versus 2017 due to higher receipts from Na Kika, as well as higher volumes from a third party connecting carrier due to new tie-backs connected to such system which came online throughout 2018. We expect two additional tie-backs coming online in the first quarter of 2019 to provide incremental volume through the Odyssey and Delta systems.
Transportation volumes on Amberjack were higher in 2018 versus 2017 driven by increased production from two large fields in the central Gulf of Mexico.
Transportation volumes on Mars were higher in 2018 versus 2017 driven by increased production from three large fields in the central Gulf of Mexico, as well as from an increase in receipt volume from a connecting pipeline system. The increase in transportation volumes was partially offset by lower storage volumes in 2018 versus 2017. Additionally, there was a planned producer turnaround that impacted the second quarter of 2018.

Major Maintenance Projects

On the Zydeco pipeline system, we are in the execution stage of a directional drill project to address soil erosion over a two-mile section of our 22-inch diameter pipeline under the Atchafalaya River and Bayou Shaffer in Louisiana (the “directional drill project”). The project commenced in the latter half of 2017. Due to a change in service provider, as well as allowing for performance of the work during optimal weather and water conditions, construction timing has been delayed and we now expect the project to be completed in the first half of 2019. Zydeco expects to incur approximately $43.0 million in maintenance capital expenditures for the total project. Since inception, Zydeco has incurred $31.2 million, of which $12.2 million was in 2018. In connection with the acquisitions of additional interests in Zydeco, SPLC agreed to reimburse us against our proportionate share of certain costs and expenses with respect to this project. During 2018, we filed claims for reimbursement from SPLC of $11.4 million which were treated as capital contributions from our Parent.
In June 2017, a small release of approximately 23 gallons of crude oil occurred on the Zydeco pipeline near Erath, Louisiana. The portion of the pipeline impacted was repaired and returned to service. We ran an in-line inspection tool, hydro-tested the system and invested in additional equipment to mitigate the effects of pressure cycling in the future. The hydro-test resulted in the Zydeco pipeline from Houston, Texas to Houma, Louisiana being out of service for 49 days in the first quarter of 2018. Offshore volumes flowing into destination markets were not impacted. The impact to net income and cash available for distribution was approximately $60.0 million in the first quarter of 2018. Final remediation activities were completed in the second quarter of 2018 with no material impact.
In November 2017, the Enchilada platform in Garden Banks Block 128 experienced a fire that resulted in the shut-in of all production flowing through Auger. The platforms contributing a majority of Auger’s daily throughput returned to service in the first quarter of 2018, and the remaining impacted platforms resumed production in the third quarter of 2018. As such, the impact to net income and cash available for distribution was approximately $11.0 million in 2018. We filed a claim under our business continuity insurance and expect to partially recover losses occurring 60 days or more after the incident. Under this claim we received $6.5 million in 2018 and recorded it in Other income in our consolidated statements of income, and expect to receive approximately $3.0 million in the first half of 2019.
In the beginning of the fourth quarter of 2017, fields connecting to Odyssey went offline due to operational issues and came back online early in the third quarter of 2018. The impact to net income and cash available for distribution for Odyssey and Delta was approximately $9.0 million in the first half of 2018.
In the second quarter of 2018, Mars experienced lower volumes due to a planned producer turnaround. The impact to net income and cash available for distribution was approximately $7.0 million. Volumes returned to anticipated levels in the third quarter of 2018.
On the Refinery Gas Pipeline system, a project to convert a section of pipe from the Convent refinery to Sorrento from refinery gas service to butane service was put on hold due to the refinery’s decision to continue the operation of its catalytic converter. In connection with the acquisition of the Refinery Gas Pipeline asset, Shell Chemical agreed to

reimburse us for our share of certain costs and expenses with respect to the conversion project. During 2017, we incurred costs and expenses related to the project, and filed claims for reimbursement from Shell Chemical, of $1.7 million, which were treated as capital contributions
56

from our Parent. With the project suspended, we incurred immaterial maintenance capital expenditures to close out this project in 2018.

Certain connected producers have turnarounds planned for 2019. The expected impact to net income and cash available for distribution is approximately $10.0 million in each of the second and third quarters of 2019.

For expected capital expenditures in 2019, refer to *Capital Resources and Liquidity - Capital Expenditures.*

Major Expansion Projects

In June 2017, Zydeco began construction on a tank expansion project in Houma to address future capacity shortfalls during tank maintenance which will allow us to service additional capacity, as well as allow for existing tanks to come out of service for regularly scheduled inspection and maintenance. We are building two 250,000 barrel working tanks at the existing Houma facility for a total of $44.1 million in growth capital expenditures. Since inception, Zydeco has incurred $39.7 million, of which $22.4 million was incurred in 2018. Beginning in January 2019, one of the tanks is in service, and the second tank is expected to be in service later in the first quarter of 2019. The project is expected to be completed during the first quarter of 2019. The scope includes interconnecting piping, dike expansion and associated facility work.

On Amberjack, we expect an increase in volume going forward due to multiple production expansion projects. We anticipate this will result in an increase in equity investment income and distributions received from Amberjack. See "*Factors Affecting Our Business and Outlook*" for additional information.

Customers

We transport and store crude oil, refined products, natural gas, and refinery gas for a broad mix of customers, including producers, refiners, marketers and traders, and are connected to other crude oil and refined products pipelines. In addition to serving directly-connected U.S. Gulf Coast markets, our crude oil and refined products pipelines have access to customers in various regions of the United States through interconnections with other major pipelines. Our customers use our transportation and storage services for a variety of reasons. Refiners typically require a secure and reliable supply of crude oil over a prolonged period of time to meet the needs of their specified refining diet and frequently enter into long-term firm transportation agreements to ensure a ready supply of crude oil, rate surety and sometimes sufficient transportation capacity over the life of the contract. Similarly, chemical sites require a secure and reliable supply of refinery gas to crackers and enter into long-term firm transportation agreements to ensure steady supply. Producers of crude oil and natural gas require the ability to deliver their product to market and frequently enter into firm transportation contracts to ensure that they will have sufficient capacity available to deliver their product to delivery points with greater market liquidity. Marketers and traders generate income from buying and selling crude oil and refined products to capitalize on price differentials over time or between markets. Our customer mix can vary over time and largely depends on the crude oil and refined products supply and demand dynamics in our markets. Refer to *Note 13 - Transactions with Major Customers and Concentration of Credit Risk* in the *Notes to the Consolidated Financial Statements* included in *Part II, Item 8* for additional information.

Competition

Our pipeline systems compete primarily with other interstate and intrastate pipelines and with marine and rail transportation. Some of our competitors may expand or construct transportation systems that would create additional competition for the services we provide to our customers. For example, newly constructed transportation systems in the onshore Gulf of Mexico region may increase competition in the markets where our pipelines operate. In addition, future pipeline transportation capacity could be constructed in excess of actual demand, which could reduce the demand for our services, in the market areas we serve, and could lead to the reduction of the rates that we receive for our services. While we do see some variation from quarter-to-quarter resulting from changes in our customers' demand for transportation, this risk has historically been mitigated by the long-term, fixed rate basis upon which we have contracted a substantial portion of our capacity. However, contracts that represented approximately 30% of our revenues for both the years ended December 31, 2018 and 2017 expired in December 2018 or will expire in 2019. Our business may be negatively affected if we are unable to renew or replace our contract portfolio on comparable terms. See "*Changes in Customer Contracting*" for additional information.

Our storage terminal competes with surrounding providers of storage tank services. Some of our competitors have expanded terminals and built new pipeline connections, and third parties may construct pipelines that bypass our location. These, or similar events, could have a material adverse impact on our operations.

Our refined products terminals generally compete with other terminals that serve the same markets. These terminals may be owned by major integrated oil and gas companies or by independent terminaling companies. While fees for terminal storage and

57

throughput services are not regulated, they are subject to competition from other terminals serving the same markets. However, our contracts provide for stable, long-term revenue, which is not impacted by market competitive forces.

Regulation

Our assets are subject to regulation by various federal, state and local agencies.

In May 2018, Zydeco, Mars, LOCAP and Colonial filed with FERC to increase rates subject to FERC's indexing adjustment methodology by approximately 4.4% starting on July 1, 2018.

In March 15, 2018, FERC issued its Revised Policy Statement on Treatment of Income Taxes in Docket No. PL17-1-000 and on July 18, 2018, FERC issued Order No. 849, which adopts procedures to address the impact of the TCJA for natural gas pipelines. In the Revised Policy Statement on Treatment of Income Taxes, FERC eliminated the recovery of an income tax allowance by an MLP oil and gas pipelines in cost-of-service-based rates. In Order No. 849, however, FERC has clarified its general disallowance of MLP income tax allowance recovery by providing that an MLP will not be precluded in a future proceeding from making a claim that it is entitled to an income tax allowance. FERC will permit an MLP to demonstrate that its recovery of an income tax allowance does not result in a "double-recovery of investors' income tax costs." FERC originally issued the March 2018 Revised Policy Statement following remand of a proceeding from the United States Court of Appeals for the D.C. Circuit. In United Airlines, Inc. v. FERC, the D.C. Circuit vacated a pair of FERC orders to the extent they permitted an interstate refined petroleum products pipeline owned by an MLP to include an income tax allowance in its cost-of-service rates. The D.C. Circuit held that FERC had failed to demonstrate that the inclusion of an income tax allowance in the pipeline's rates would not lead to a double recovery of income tax costs attributable to regulated service and instructed FERC on remand to fashion a remedy to ensure that the pipeline's rates do not allow it to over-recover its costs.

At this time, FERC has not taken any industry-wide action regarding review of rates for crude oil and liquids pipelines. However, under the Revised Policy Statement on Treatment of Income Taxes, MLP owned crude oil and liquids pipelines are now required to report Page 700 information in their FERC Form 6 annual reports for the year ending December 31, 2017 that reflects elimination of the income tax allowance for both 2016 and 2017 reporting years. FERC also states in the policy statement that it will address the impact of the elimination of the income tax allowance as part of its five-year review of the oil pipeline rate index level in 2020. FERC can also implement the elimination of the income tax allowance in proceedings involving review of initial cost-of-service rates, rate changes, and rate complaints. For crude oil and liquids pipelines owned by non-MLP partnerships and other pass-through businesses, FERC will address such issues as they arise in subsequent proceedings.

We believe that FERC's decisions on income tax allowances in 2018 will not have a material impact on our operations and financial performance. Since FERC only maintains jurisdiction over interstate crude oil and liquids pipelines, the recent decisions are not expected to have an impact on rates charged through our offshore operations. FERC also does not maintain jurisdiction over certain of the onshore assets in which we have interests. Rates related to these assets should not be impacted by the FERC decision. For our FERC-regulated rates charged through our interstate crude oil and liquids pipelines, the rates are based on either a negotiated or market-based rate, which are below the cost-of-service rates established by FERC. As such, neither our negotiated nor market-based rate revenue for our FERC-regulated assets would be subject to the income tax recovery disallowance. Additionally, we have evaluated the impact of FERC's recent policy changes on our non-operated joint ventures. Due to the nature of their assets, operations and/or their entity form, we do not believe there will be any material impact to their operations and earnings.

On October 20, 2016, the Federal Energy Regulatory Commission issued an Advance Notice of Proposed Rulemaking in Docket No. RM17-1-000 regarding changes to the oil pipeline rate index methodology and data reporting on the Page 700 of the FERC Form No. 6. In an effort to improve the Commission's ability to ensure that oil pipeline rates are just and reasonable under the ICA, the Commission is considering making the following changes to their current indexing methodologies for oil pipelines:

1) Deny index increases for any pipeline whose Form No. 6, Page 700 revenues exceed costs by 15% for both of the prior two years;

2) Deny index increases that exceed by 5% the cost changes reported on Page 700; and
3) Apply the new criteria to costs more closely associated with the pipeline's proposed rates than with total company-wide costs and revenues now reported on Page 700.

Initial comments were filed on January 19, 2017, and reply comments were filed on March 17, 2017. We will continue to monitor developments in this area.

Acquisition Opportunities
We plan to continue to pursue acquisitions of complementary assets from SPLC and other subsidiaries of Shell, as well as from third parties. Since our initial public offering, we have acquired approximately $4,900.0 million of assets from Shell and its affiliates. We also may pursue acquisitions jointly with SPLC. Given the size and scope of SPLC's footprint and its significant ownership interest in us, we expect acquisitions from SPLC will be an important growth mechanism for the foreseeable future. Neither SPLC nor any of its affiliates is under any obligation, however, to sell or offer to sell us additional assets or to pursue acquisitions jointly with us, and we are under no obligation to buy any additional assets from them or to pursue any joint acquisitions with them. We will continue to focus our acquisition strategy on transportation and midstream assets. We believe that we will be well positioned to acquire midstream assets from SPLC, other subsidiaries of Shell, and third parties should such opportunities arise. Identifying and executing acquisitions is a key part of our strategy. However, if we do not make acquisitions on economically acceptable terms or if we incur a substantial amount of debt in connection with the acquisitions, our future growth will be limited, and the acquisitions we do make may reduce, rather than increase, our available cash. Our ability to obtain financing or access capital markets may also directly impact our ability to continue to pursue strategic acquisitions. Current market demand for equity issued by MLP's may make it more challenging for us to fund our acquisitions with the issuance of equity in capital markets. As such, we maintain a conservative balance sheet, providing us other financing options such as hybrid securities, sponsor take-backs and debt.

Results of Operations

	2018		**2017**		**2016**	
Revenue (1)	$	524.7	$	470.1	$	452.9
Costs and expenses						
Operations and maintenance (1)	161.9		149.7		116.9	
Cost of product sold (1)	32.7		—		—	
(Gain) loss from revision of ARO and disposition of fixed assets	(3.4)		0.1		0.2	
General and administrative	59.5		57.8		53.4	
Depreciation, amortization and accretion	45.9		45.0		43.1	
Property and other taxes	15.9		17.4		15.8	
Total costs and expenses (1)	312.5		270.0		229.4	
Operating income	212.2		200.1		223.5	
Income from equity method investments	234.9		186.6		138.1	

Dividend income from other investments	66.8		37.4		28.3	
Other income (loss)	31.4		—		(0.1)	
Investment, dividend and other income (loss)	333.1		224.0		166.3	
Interest expense, net	62.5		32.2		12.3	
Income before income taxes	482.8		391.9		377.5	
Income tax expense	0.4		0.1		—	
Net income	482.4		391.8		377.5	
Less: Net income attributable to the Parent	—		77.3		102.3	
Less: Net income attributable to noncontrolling interests	18.3		19.2		30.3	
Net income attributable to the Partnership	$	464.1	$	295.3	$	244.9
General partner's interest in net income attributable to the Partnership	$	134.4	$	64.6	$	25.0
Limited Partners' interest in net income attributable to the Partnership	$	329.7	$	230.7	$	219.9
Adjusted EBITDA attributable to the Partnership (2)	$	616.7	$	380.1	$	294.9
Cash available for distribution attributable to the Partnership (2)	$	536.3	$	360.0	$	273.2

(1) As a result of the adoption of the new revenue standard, prior period amounts have not been adjusted under the modified retrospective method and continue to be reported in accordance with our historic accounting under previous GAAP.

(2) For a reconciliation of Adjusted EBITDA and Cash available for distribution attributable to the Partnership to their most comparable GAAP measures, please read "—Reconciliation of Non-GAAP Measures."

Pipeline throughput (thousands of barrels per day) (1)	**2018**	**2017**	**2016**
Zydeco - Mainlines	623	611	568
Zydeco - Other segments	249	359	478
Zydeco total system	872	970	1,046
Amberjack total system	324	256	196
Mars total system	516	469	388
Bengal total system	539	581	547
Poseidon total system	235	254	265
Auger total system	58	60	