GENESIS ENERGY LP
Form 10-K
February 28, 2019
Table of Contents

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
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

Commission file number 1-12295
GENESIS ENERGY, L.P.
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| Delaware | 76-0513049 |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |

919 Milam, Suite 2100, Houston, TX 77002
(Address of principal executive offices) (Zip code)
(713) 860-2500
Registrant's telephone number, including area code:
Securities registered pursuant to Section 12(b) of the Act:

| Title of Each Class | Name of Each Exchange on Which Registered |
|---|---|
| Common Units | NYSE |

Securities registered pursuant to Section 12(g) of the Act:
NONE
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No o
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 o No x
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o
Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T(§232.45 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.005 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o
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 | o | Smaller reporting company | ¨ |

Emerging growth company ¨

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

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

The aggregate market value of the Class A common units held by non-affiliates of the Registrant on June 30, 2018(the last business day of Registrant's most recently completed second fiscal quarter) was approximately $2.3 billion based on $21.91 per unit, the closing price of the common units as reported on the NYSE. For purposes of this computation, all executive officers, directors and 10% owners of the registrant are deemed to be affiliates. Such a determination should not be deemed an admission that such executive officers, directors and 10% beneficial owners are affiliates. On February 28, 2019, the Registrant had 122,539,221 Class A Common Units and 39,997 Class B Common Units outstanding.

Table of Contents

GENESIS ENERGY, L.P.
2018 FORM 10-K ANNUAL REPORT
Table of Contents

Table of Contents

Definitions

Unless the context otherwise requires, references in this annual report to "Genesis Energy, L.P.," "Genesis," "we," "our," "us" like terms refer to Genesis Energy, L.P. and its operating subsidiaries. As generally used within the energy industry and in this annual report, the identified terms have the following meanings:

Bbl or Barrel: One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to crude oil or other liquid hydrocarbons.
Bbls/day: Barrels per day.
Bcf: Billion cubic feet of gas.
$CO_2$: Carbon dioxide.
DST: Dry short tons (2,000 pounds), a unit of weight measurement.
FERC: Federal Energy Regulatory Commission.
Gal: Gallon.
MBbls: Thousand Bbls.
MBbls/d: Thousand Bbls per day.
Mcf: Thousand cubic feet of gas.
mmBtu: One million British thermal units, an energy measurement.
MMcf: Thousand Mcf.
NaHS: (commonly pronounced as "nash") Sodium hydrosulfide.
NaOH or Caustic Soda: Sodium hydroxide.
Natural gas liquid(s) or NGL(s): The combination of ethane, propane, normal butane, isobutane and natural gasolines that, when removed from natural gas, become liquid under various levels of higher pressure and lower temperature.
Sour gas: Natural gas containing more than four parts per million of hydrogen sulfide.
Wellhead: The point at which the hydrocarbons and water exit the ground.

FORWARD-LOOKING INFORMATION

The statements in this Annual Report on Form 10-K that are not historical information may be "forward looking statements" as defined under federal law. All statements, other than historical facts, included in this document that address activities, events or developments that we expect or anticipate will or may occur in the future, including things such as plans for growth of the business, future capital expenditures, competitive strengths, goals, references to future goals or intentions, estimated or projected future financial performance, and other such references are forward-looking statements, and historical performance is not necessarily indicative of future performance. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "continue," "estimate," "expect," "forecast," "goal," "intend," "may," "could," "plan," "positio "strategy," "should" or "will," or the negative of those terms or other variations of them or by comparable terminology. In particular, statements, expressed or implied, concerning future actions, conditions or events or future operating results or the ability to generate sales, income or cash flow are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability or the ability of our affiliates to control or predict. Specific factors that could cause actual results to differ from those in the forward-looking statements include, among others:

- demand for, the supply of, our assumptions about, changes in forecast data for, and price trends related to crude oil, liquid petroleum, natural gas, NaHS, soda ash,caustic soda and $CO_2$, all of which may be affected by economic activity, capital expenditures by energy producers, weather, alternative energy sources, international events, conservation and technological advances;

Table of Contents

- our ability to successfully execute our business and financial strategies;
- throughput levels and rates;
- changes in, or challenges to, our tariff rates;
- our ability to successfully identify and close strategic acquisitions on acceptable terms (including obtaining third-party consents and waivers of preferential rights), develop or construct infrastructure assets, make cost saving changes in operations and integrate acquired assets or businesses into our existing operations;
- service interruptions in our pipeline transportation systems, and processing operations;
- shutdowns or cutbacks at refineries, petrochemical plants, utilities, individual plants or other businesses for which we transport crude oil, petroleum, natural gas or other products or to whom we sell soda ash, petroleum or other products;
- risks inherent in marine transportation and vessel operation, including accidents and discharge of pollutants;
- changes in laws and regulations to which we are subject, including tax withholding issues, regulations regarding qualifying income, accounting pronouncements, and safety, environmental and employment laws and regulations;
- the effects of production declines resulting from a suspension of drilling in the Gulf of Mexico;
- planned capital expenditures and availability of capital resources to fund capital expenditures, and our ability to access the credit and capital markets to obtain financing on terms we deem acceptable;
- our inability to borrow or otherwise access funds needed for operations, expansions or capital expenditures as a result of our credit agreement and the indentures governing our notes, which contain various affirmative and negative covenants;
- loss of key personnel;
- cash from operations that we generate could decrease or fail to meet expectations, either of which could reduce our ability to pay quarterly cash distributions at the current level, pay our quarterly dividend on our preferred units, or to increase quarterly cash distributions in the future;
- an increase in the competition that our operations encounter;
- cost and availability of insurance;
- hazards and operating risks that may not be covered fully by insurance;
- our financial and commodity hedging arrangements, which may reduce our earnings, profitability and cash flow;
- changes in global economic conditions, including capital and credit markets conditions, inflation and interest rates;
- natural disasters, accidents or terrorism;
- changes in the financial condition of customers or counterparties;
- adverse rulings, judgments, or settlements in litigation or other legal or tax matters;
- the treatment of us as a corporation for federal income tax purposes or if we become subject to entity-level taxation for state tax purposes; and
- the potential that our internal controls may not be adequate, weaknesses may be discovered or remediation of any identified weaknesses may not be successful and the impact these could have on our unit price.

You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please review the risk factors described under “Risk Factors” discussed in Item 1A. These risks may also be specifically described in our Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and Form 8-K/A and other documents that we may file from time to time with the SEC. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Table of Contents

PART I

Item 1. Business

General

We are a growth-oriented master limited partnership formed in Delaware in 1996. Our common units are traded on the New York Stock Exchange, or NYSE, under the ticker symbol “GEL.” We are (i) a provider of an integrated suite of midstream services - primarily transportation, storage, sulfur removal, blending, terminalling and processing - for a large area of the Gulf Coast region of the crude oil and natural gas industry and (ii) one of the leading producers in the world of natural soda ash. Our sulfur removal business results in us being the largest producer, we believe, in the world of sodium hydrosulfide (or NaHS, pronounced “nash”).
Historically, a substantial majority of our focus has been on the midstream segment of the crude oil and natural gas industry in the Gulf of Mexico and the Gulf Coast region of the United States. We provide an integrated suite of services to refiners, crude oil and natural gas producers, and industrial and commercial enterprises and have a diverse portfolio of assets, including pipelines, offshore hub and junction platforms, refinery-related plants, storage tanks and terminals, railcars, rail unloading facilities, barges and other vessels, and trucks.
On September 1, 2017, we acquired our trona and trona-based exploring, mining, processing, producing, marketing and selling business based in Wyoming (our “Alkali Business”) for approximately $1.325 billion in cash. Our Alkali Business mines and processes trona from which it produces natural soda ash, also known as sodium carbonate ($Na_2CO_3$), a basic building block for a number of ubiquitous products, including flat glass, container glass, dry detergent and a variety of chemicals and other industrial products. Our Alkali business has a diverse customer base in the United States, Canada, the European Community, the European Free Trade Area and the South African Customs Union with many long-term relationships. It has been operating for almost 70 years and has an estimated remaining reserve life of over 100 years.
Within our legacy midstream business, we have two distinct, complementary types of operations- (i) our offshore Gulf of Mexico crude oil and natural gas pipeline transportation and handling operations, which focus on providing a suite of services primarily to integrated and large independent energy companies who make intensive capital investments to develop numerous large-reservoir, long-lived crude oil and natural gas properties and (ii) our onshore-based refinery-centric operations located primarily in the Gulf Coast region of the U.S., which focus on providing a suite of services primarily to refiners, which includes our sulfur removal, transportation, storage, and other handling services. Our onshore-based operations occur upstream of, at, and downstream of refinery complexes. Upstream of refineries, we aggregate, purchase, gather and transport crude oil, which we sell to refiners. Within refineries, we provide services to assist in sulfur removal/balancing requirements. Downstream of refineries, we provide transportation services as well as market outlets for finished refined petroleum products and certain refining by-products. In our offshore crude oil and natural gas pipeline transportation and handling operations, we provide services to one of the most active drilling and development regions in the U.S.-the Gulf of Mexico, a producing region representing approximately 16% of the crude oil production in the U.S. in 2018.
Our operations include, among others, the following diversified businesses, each of which is one of the leaders in its market, has a long commercial life and has significant barriers to entry:

- one of the largest pipeline networks (based on throughput capacity) in the Deepwater area of the Gulf of Mexico, an area that produced approximately 16% of the oil produced in the U.S. in 2018,
- the largest producer and marketer (based on tons produced), we believe, of NaHS in North and South America,
- one of the leading producers (based on tons produced) of natural soda ash in the world, and
- one of the largest providers of crude oil and petroleum transportation, storage, and other handling services for large, complex refineries in Baton Rouge, Louisiana and Baytown, Texas, both of which have been operational for approximately 100 years.

On October 11, 2018, we completed the divestiture of our Powder River Basin midstream assets, which were historically reported in our onshore facilities and transportation segment. We received net proceeds of approximately $300 million for the sale.

We conduct our operations and own our operating assets through our subsidiaries and joint ventures. Our general partner, Genesis Energy, LLC, a wholly-owned subsidiary that owns a non-economic general partner interest in us, has sole responsibility for conducting our business and managing our operations. Our outstanding common units (including our Class B common units), and our outstanding Class A convertible preferred units, representing limited partner interests, constitute all of the economic equity interests in us.

Table of Contents

We currently manage our businesses through four divisions that constitute our reportable segments - offshore pipeline transportation, sodium minerals and sulfur services, onshore facilities and transportation and marine transportation. For additional information, please review the section entitled "Financial Measures."

Offshore Pipeline Transportation Segment

We conduct our offshore crude oil and natural gas pipeline transportation and handling operations through our offshore pipeline transportation segment, which focuses on providing a suite of services to integrated and large independent energy companies who make intensive capital investments (often in excess of billions of dollars) to develop numerous large-reservoir, long-lived crude oil and natural gas properties in the Gulf of Mexico, primarily offshore Texas, Louisiana, Mississippi and Alabama. This segment provides services to one of the most active drilling and development regions in the U.S.—the Gulf of Mexico, a producing region representing approximately 16% of the crude oil production in the U.S. in 2018. Even though those large-reservoir properties and the related pipelines and other infrastructure needed to develop them are capital intensive, we believe they are generally much less sensitive to short-term commodity price volatility, particularly once a project has been sanctioned. Due to the size and scope of these activities, our customers are predominantly large integrated oil companies and large independent crude oil producers.

We own interests in various offshore crude oil and natural gas pipeline systems, platforms and related infrastructure. We own interests in approximately 1,422 miles of crude oil pipelines with an aggregate design capacity of approximately 1,800 MBbls per day, a number of which pipeline systems are substantial and/or strategically located. For example, we own a 64% interest in the Poseidon pipeline system and 100% of the Cameron Highway pipeline system, or CHOPS, which is one of the largest crude oil pipelines (in terms of both length and design capacity) located in the Gulf of Mexico. We also own 100% of the Southeast Keathley Canyon Pipeline Company, LLC ("SEKCO"), which is a deepwater pipeline servicing the Lucius field in the southern Keathley Canyon area of the Gulf of Mexico.

Our interests in offshore natural gas pipeline systems and related infrastructure includes approximately 970 miles of pipe with an aggregate design capacity of approximately 3,313 MMcf per day. We also own an interest in four offshore hub platforms with aggregate processing capacity of approximately 711 MMcf per day of natural gas and 159 MBbls per day of crude oil.

Our offshore pipelines generate cash flows from fees charged to customers or substantially similar arrangements that otherwise limit our direct exposure to changes in commodity prices. Each of our offshore pipelines currently has significant available capacity (with minimal to no additional capital investment required from us) to accommodate future growth in the fields from which the production is dedicated to that pipeline, including fields that have yet to commence production activities, as well as volumes from non-dedicated fields.

Sodium Minerals and Sulfur Services Segment

Our Alkali business owns the largest leasehold position of accessible trona ore reserves in the Green River, Wyoming trona patch, a geological formation holding the vast majority of the world’s accessible trona ore reserves. Our Alkali Business holds leases covering approximately 88,000 acres of land, containing an estimated 903 million metric tonnes of proved and probable reserves of trona ore, representing an estimated remaining reserve life of over 100 years, soda ash production facilities, underground trona ore mines and solution mining operations and related equipment, logistics and other assets.

Our Alkali Business has been mining trona and producing soda ash in the Green River, Wyoming trona patch for almost 70 years. All of our Alkali Business’ mining and processing activities are conducted at its “Westvaco” and “Granger” facilities in Wyoming. Utilizing our two facilities near Green River, WY, our Alkali Business involves the mining of trona ore, processing the trona ore into soda ash, also known as sodium carbonate ($Na_2Co_3$), and the marketing, selling and distribution of the soda ash and specialty products.

We sell our soda ash and specialty products to a diverse customer base directly in the United States, Canada, the European Community, the European Free Trade Area and the South African Customs Union. Our Alkali Business also sells through the American Natural Soda Ash Corporation, or ANSAC, exclusively in all other markets. ANSAC is a nonprofit foreign sales association of which our Alkali Business and two other U.S. soda ash producers are members, whose purpose is to promote export sales of U.S. produced soda ash in conformity with the Webb-Pomerene Act. ANSAC is our Alkali Business' largest customer. See Note 15 for a further discussion of ANSAC.

Soda ash is utilized by our customers as a basic building block for a number of ubiquitous products, including flat glass, container glass, dry detergent and a variety of chemicals and other industrial products. The global market in which our Alkali Business operates is competitive. Competition is based on a number of factors such as price, favorable logistics and consistent customer service. In North America, primary competition is from other U.S.-based natural soda ash operations: Solvay Chemicals, Ciner Resources, L.P., Tata Chemicals Soda Ash Partners in Wyoming, and Searles Valley Minerals, in California.

As part of our sulfur removal business, we primarily (i) provide services to ten refining operations located mostly in Texas, Louisiana, Arkansas, Oklahoma, Montana and Utah; (ii) operate significant storage and transportation assets in relation to those services; and (iii) sell NaHS and NaOH (also known as caustic soda) to large industrial and commercial companies. Our sulfur removal services primarily involve processing refiners' high sulfur (or "sour") gas streams to remove the sulfur. Our sulfur removal services footprint also includes NaHS and caustic soda terminals, and we utilize railcars, ships, barges and trucks to transport product. Our sulfur removal services contracts are typically long-term in nature and have an average remaining term of four and a half years. NaHS is a by-product derived from our refinery sulfur removal services process, and it constitutes the sole consideration we receive for these services. A majority of the NaHS we receive is sourced from refineries owned and operated by large companies, including Phillips 66, CITGO, HollyFrontier, Calumet and Ergon. We sell our NaHS to customers in a variety of industries, with the largest customers involved in mining of base metals, primarily copper and molybdenum, and the production of pulp and paper. We believe we are one of the largest producers and marketers of NaHS in North and South America.

Onshore Facilities and Transportation Segment

Our onshore facilities and transportation segment owns and/or leases our increasingly integrated suite of onshore crude oil and refined products infrastructure, including pipelines, trucks, terminals, railcars, and rail unloading facilities. It uses those assets, together with other modes of transportation owned by third parties and us, to service its customers and for its own account. The increasingly integrated nature of our onshore facilities and transportation assets is particularly evident in certain of our recently completed infrastructure projects in areas such as Louisiana and Texas.

Usually, our onshore facilities and transportation segment experiences limited direct commodity price risk because it utilizes back-to-back purchases and sales, matching sale and purchase volumes on a monthly basis. Unsold volumes are hedged with NYMEX derivatives to offset the remaining price risk.

We own four onshore crude oil pipeline systems, with approximately 450 miles of pipe located primarily in Alabama, Florida, Louisiana, Mississippi and Texas. The Federal Energy Regulatory Commission, or FERC, regulates the rates charged by four of our onshore systems to their customers. The rates for the other onshore pipeline are regulated by the Railroad Commission of Texas. Our onshore pipelines generate cash flows from fees charged to customers. Each of our onshore pipelines has significant available capacity to accommodate potential future growth in volumes.

We own four operational crude oil rail unloading facilities located in Baton Rouge, Louisiana; Raceland, Louisiana; Walnut Hill, Florida; and Natchez, Mississippi which provide synergies to our existing asset footprint. We generally earn a fee for unloading railcars at these facilities. Three of these facilities, our Baton Rouge, Louisiana, Raceland, Louisiana, and Walnut Hill, Florida facilities are directly connected to our existing integrated crude oil pipeline and terminal infrastructure. In addition to the above, we have access to a suite of approximately 200 trucks, 300 trailers, 404 railcars, and terminals and tankage with 4.6 million barrels of storage capacity (excluding capacity associated with our common carrier crude oil pipelines) in multiple locations along the Gulf Coast.

We own two $CO_2$ pipelines with approximately 270 miles of pipe. We have leased our NEJD System, comprised of 183 miles of pipe in North East Jackson Dome, Mississippi, to an affiliate of an independent crude oil company through 2028. We receive a fixed quarterly payment under the NEJD arrangement. That company also has the exclusive right to use our Free State pipeline, comprised of 86 miles of pipe, pursuant to a transportation agreement that expires in 2028. Payments on the Free State pipeline are subject to an "incentive" tariff which provides that the average rate per mcf that we charge during any month decreases as our aggregate throughput for that month increases above specified thresholds.

Marine Transportation Segment

We own a fleet of 91 barges (82 inland and 9 offshore) with a combined transportation capacity of 3.2 million barrels and 42 push/tow boats (33 inland and 9 offshore). Our marine transportation segment is a provider of transportation services by tank barge primarily for refined petroleum products, including heavy fuel oil and asphalt, as well as crude oil. Refiners accounted for over 80% of our marine transportation volumes for 2018.

We also own the M/T American Phoenix, an ocean going tanker with 330,000 barrels of cargo capacity. The M/T American Phoenix is currently transporting refined products.

We are a provider of transportation services for our customers and, in almost all cases, do not assume ownership of the products that we transport. Our marine transportation services are conducted under term contracts, some of which have renewal options for customers with whom we have traditionally had long-standing relationships, and spot contracts. For more information regarding our charter arrangements, please refer to the marine transportation segment discussion below. All of our vessels operate under the U.S. flag and are qualified for domestic trade under the Jones Act.

Table of Contents

Our Objectives and Strategies

Our primary objective continues to be to generate and grow stable cash flows while never wavering from our commitment to safe and responsible operations. In 2017, we made the strategic decision to re-set our quarterly distribution and provided a plan for visible, achievable long term distribution growth and a clear path forward to deleveraging. We believe these steps, along with the (i) stable and repeatable cash flows from our Alkali Business, for 2017, 2018 and the foreseeable future, due to its long-lived trona reserves; (ii) the contribution achieved during 2018 from certain of our recent strategic investments, and (iii) proceeds received during 2018 from the sale of certain of our non-core assets located in the Powder River Basin provide a clear path forward to our goal of reducing our overall indebtedness and deleveraging, and further enhancing our financial flexibility to opportunistically pursue accretive organic projects and acquisitions should they present themselves.

Business Strategy

Our primary business strategy is to provide an integrated suite of services to refiners, crude oil and natural gas producers, and industrial and commercial enterprises. Successfully executing this strategy should enable us to generate and grow stable cash flows.

On September 1, 2017, we acquired our Alkali Business, which is one of the world's leading producers of natural soda ash. Natural soda ash accounts for approximately 25% of the world’s production of soda ash. We believe the significant cost advantage in the production of natural soda ash over synthetically produced soda ash will remain for the foreseeable future, somewhat mitigating the effects of market specific factors in the soda ash market in which we operate.

Within our legacy midstream business, we have two distinct, complementary types of operations: (i) our offshore Gulf of Mexico crude oil and natural gas pipeline transportation and handling operations, focusing on integrated and large independent energy companies who make intensive capital investments (often in excess of billions of dollars) to develop numerous large-reservoir, long-lived crude oil and natural gas properties; and (ii) our onshore-based-refinery-centric operations located primarily in the Gulf Coast region of the U.S., which focus on providing a suite of services primarily to refiners. In 2018, refiners were the shippers of approximately 80% of the volumes transported on our onshore crude pipelines, and refiners contract for over 80% of the use of our inland barges, which are used primarily to transport intermediate refined products (not crude oil) between refining complexes. The integrated and large independent energy companies that use our offshore oil pipelines produce oil that is ideally suited for the vast majority of refineries along the Gulf Coast, unlike the lighter crude oil and condensates produced from numerous onshore shale plays.

We intend to develop our business by:

- Identifying and exploiting incremental profit opportunities, including cost synergies, across an increasingly integrated footprint;
- Optimizing our existing assets and creating synergies through additional commercial and operating advancement;
- Leveraging customer relationships across business segments;
- Attracting new customers and expanding our scope of services offered to existing customers;
- Expanding the geographic reach of our businesses;
- Economically expanding our pipeline and terminal operations by utilizing capacity currently available on our existing assets that requires minimal to no additional investment;
- Evaluating internal and third party growth opportunities (including asset and business acquisitions) that leverage our core competencies and strengths and further integrate our businesses; and
- Focusing on health, safety and environmental stewardship.

Table of Contents

Financial Strategy

We believe that preserving financial flexibility is an important factor in our overall strategy and success. Over the long-term, we intend to:

- Increase the relative contribution of recurring and throughput-based revenues, emphasizing longer-term contractual arrangements;
- Prudently manage our limited direct commodity price risks;
- Maintain a sound, disciplined capital structure, including our previously announced guidance outlying our current and forward path to deleveraging; and
- Create strategic arrangements and share capital costs and risks through joint ventures and strategic alliances.

Competitive Strengths

We believe we are well positioned to execute our strategies and ultimately achieve our objectives due primarily to the following competitive strengths:

- Our businesses encompass a balanced, diversified portfolio of customers, operations and assets. We operate four business segments and own and operate assets that enable us to provide a number of services primarily to refiners, crude oil and natural gas producers, and industrial and commercial enterprises that use natural soda ash, NaHS and caustic soda. Our business lines complement each other by allowing us to offer an integrated suite of services to common customers across segments. Our businesses are primarily focused on (i) providing offshore crude oil and natural gas pipeline transportation and related handling services in the Gulf of Mexico to mostly integrated and large independent energy companies (ii) producing sodium minerals and sulfur removal and (iii) providing onshore-based refinery-centric crude oil and refined products transportation and handling services. We are not dependent upon any one customer or principal location for our revenues.
- Certain of our businesses are among the leaders in each of their respective markets and each of which has a long commercial life and significant barriers to entry . We operate, among others, diversified businesses, each of which is one of the leaders in its market, has a long commercial life and has significant barriers to entry. We operate one of the largest pipeline networks (based on throughput capacity) in the Deepwater area of the Gulf of Mexico, an area that produced approximately 16% of the oil produced in the U.S. in 2018. We are one of the leading producers (based on tons produced) of natural soda ash in the world. We believe we are the largest producer and marketer (based on tons produced) of NaHS in North and South America. We are one of the largest providers of crude oil and petroleum product transportation, storage and other handling services for large, complex refineries in Baton Rouge, Louisiana and Baytown, Texas, both of which have been operational for approximately 100 years.
- Our Alkali Business has significant cost advantages over synthetic production methods. Our Alkali Business has significant cost advantages over synthetic production methods, including lower raw material and energy requirements. According to IHS, on average, the cash cost to produce material soda ash has been about half of the cost to produce synthetic soda ash.
- Our businesses provide relatively consistent consolidated financial performance. Our historically consistent and improving financial performance, combined with our goal of a conservative capital structure over the long term, has allowed us to generate relatively stable and increasing cash flows.
- We are financially flexible and have significant liquidity. As of December 31, 2018, we had $728.7 million available under our $1.7 billion revolving credit agreement, including up to $182.2 million available under the $200 million petroleum products inventory loan sublimit and $98.8 million available for letters of credit. Our inventory borrowing base was $17.8 million at December 31, 2018.
- We have limited direct commodity price risk exposure in our oil and gas and NaHS businesses. The volumes of crude oil, refined products or intermediate feedstocks we purchase are either subject to back-to-back sales contracts or are hedged with NYMEX derivatives to limit our direct exposure to movements in the price of the commodity, although we cannot completely eliminate commodity price exposure. Our risk management policy requires us to monitor the effectiveness of the hedges to maintain a value at risk of such hedged inventory not in excess of $2.5 million. In

addition, our service contracts with refiners allow us to adjust the rates we charge for processing to maintain a balance between NaHS supply and demand.

- Our offshore Gulf of Mexico crude oil and natural gas pipeline transportation and handling operations are located in a significant producing region with large-reservoir, long-lived crude oil and natural gas properties. We provide a

Table of Contents

suite of services, primarily to integrated and large independent energy companies who make intensive capital investments to develop numerous large-reservoir, long-lived crude oil and natural gas properties, in one of the most active drilling and development regions in the U.S.-the Gulf of Mexico, a producing region representing approximately 16% of the crude oil production in the U.S. in 2018.

- Our expertise and reputation for high performance standards and quality enable us to provide refiners with economic and proven services. Our extensive understanding of the sulfur removal process and crude oil refining can provide us with an advantage when evaluating new opportunities and/or markets.
- Some of our pipeline transportation and related assets are strategically located. Our pipelines are critical to the ongoing operations of our refiner and producer customers. In addition, a majority of our terminals are located in areas that can be accessed by pipeline, truck, rail or barge.
- Some of our onshore facilities and transportation assets are operationally flexible. Our portfolio of trucks, railcars, barges and terminals affords us flexibility within our existing regional footprint and provides us the capability to enter new markets and expand our customer relationships.
- Our marine transportation assets provide waterborne transportation throughout North America. Our fleet of barges and boats provide service to both inland and offshore customers within a large North American geographic footprint. All of our vessels operate under the U.S. flag and are qualified for U.S. coastwise trade under the Jones Act.
- We have an experienced, knowledgeable and motivated executive management team with a proven track record. Our executive management team has an average of more than 25 years of experience in the midstream sector. Its members have worked in leadership roles at a number of large, successful public companies, including other publicly-traded partnerships. Through their equity interest in us, our executive management team is incentivized to create value by increasing cash flows.

Recent Developments and Status of Certain Growth Initiatives

The following is a brief listing of developments since December 31, 2017. Additional information regarding most of these items may be found elsewhere in this report.

Baton Rouge Area Infrastructure Expansion

We expanded our existing Baton Rouge area infrastructure to allow for greater capacity and flexibility in servicing our major refinery customer in the region. This expansion included the construction of an additional 500,000 barrels of crude oil tankage at our existing Baton Rouge Terminal. Additionally, this expansion includes the upgrading of pumping and other infrastructure capabilities in order to allow for the efficient handling of expected increases in crude oil volumes received at our Baton Rouge area facilities. These assets became operational in the first half of 2018.

Powder River Basin Midstream Assets Divestiture

On October 11, 2018, we completed the divestiture of our Powder River Basin midstream assets and received total net proceeds of approximately $300 million. The net proceeds were used to reduce the balance outstanding under our revolving credit facility.

Inland Marine Barge Delivery

In 2018, we accepted delivery of the final two new-build barges ordered during 2016. As of December 31, 2018, we have accepted delivery of all barges and boats on order.

Ownership Structure

We conduct our operations and own our operating assets through subsidiaries and joint ventures. As is customary with publicly traded limited partnerships, Genesis Energy, LLC, our general partner, is responsible for operating our business, including providing all necessary personnel and other resources.

Table of Contents

The following chart depicts our organizational structure at December 31, 2018.

Description of Segments and Related Assets

We conduct our businesses through four operating segments: offshore pipeline transportation, sodium minerals and sulfur services, onshore facilities and transportation and marine transportation. These segments are strategic business units that provide a variety of energy-related services. Financial information with respect to each of our segments can be found in Note 14 to our Consolidated Financial Statements in Item 8.

We have a diverse portfolio of customers, operations and assets, including pipelines, refinery-related plants, storage tanks and terminals, railcars, rail loading and unloading facilities, barges and other vessels, and trucks. Substantially all of our revenues are derived from providing services to refiners, integrated and large independent crude oil and natural gas companies, and large industrial and commercial enterprises. Our onshore-based operations, excluding those associated with our Alkali Business, occur upstream of, at, and downstream of refinery complexes. Upstream of refineries, we aggregate, purchase, gather and transport crude oil, which we sell to refiners. Within refineries, we provide services to assist in sulfur removal/balancing requirements. Downstream of refineries, we provide transportation services as well as market outlets for finished refined petroleum products and certain refining byproducts. Within our Alkali Business, we sell our soda ash and specialty products to a diverse customer base directly in the United States, Canada, the European Community, the European Free Trade Area and the South African Customs Union.

Offshore Pipeline Transportation

Offshore Crude Oil and Natural Gas Pipelines

We own interests in several crude oil and natural gas pipelines and related infrastructure located offshore in the Gulf of Mexico, a producing region representing approximately 16% of the crude oil production in the U.S. in 2018.

Table of Contents

The table below reflects our interests in our operating offshore crude oil pipelines:

| Offshore crude oil pipelines | Operator | System Miles | Design Capacity (Bbls/day) (1) | Interest Owned | Throughput (Bbls/day) 100% basis | Throughput (Bbls/day) net to ownership interest |
|---|---|---|---|---|---|---|
| Main Lines | | | | | | |
| CHOPS | Genesis | 380 | 500,000 | 100 % | 202,121 | 202,121 |
| Poseidon | Genesis | 358 | 350,000 | 64 % | 234,960 | 150,374 |
| Odyssey | Shell Pipeline | 120 | 200,000 | 29 % | 115,239 | 33,419 |
| Eugene Island Pipeline and Other | Genesis/Shell Pipeline | 184 | 39,000 | 29 % | 10,147 | 10,147 |
| Total | | 1,042 | 1,089,000 | | 562,467 | 396,061 |
| Lateral Lines (2) | | | | | | |
| SEKCO | Genesis | 149 | 115,000 | 100 % | | |
| Shenzi Crude Oil Pipeline | Genesis | 83 | 230,000 | 100 % | | |
| Allegheny Crude Oil Pipeline | Genesis | 40 | 140,000 | 100 % | | |
| Marco Polo Crude Oil Pipeline | Genesis | 37 | 120,000 | 100 % | | |
| Constitution Crude Oil Pipeline | Genesis | 67 | 80,000 | 100 % | | |
| Tarantula | Genesis | 4 | 30,000 | 100 % | | |

(1) Capacity figures presented represent 100% of the design capacity; except for Eugene Island, which represents our net capacity in the undivided interest (29%) in that system. Ultimate capacities can vary primarily as a result of pressure requirements, installed pumps, related facilities and the viscosity of the crude oil actually moved.

(2) Represents 100% owned lateral crude oil pipelines which, ultimately flow into our other offshore crude oil pipelines (including CHOPS and Poseidon) and thus are excluded from main lines above.

- CHOPS. CHOPS is comprised of 24- to 30-inch diameter pipelines designed to deliver crude oil from fields in the Gulf of Mexico to refining markets along the Texas Gulf Coast via interconnections with refineries located in Port Arthur and Texas City, Texas. CHOPS also includes two strategically located multi-purpose offshore platforms.
- Poseidon. The Poseidon system is comprised of 16- to 24-inch diameter pipelines to deliver crude oil from developments in the central and western offshore Gulf of Mexico to other pipelines and terminals onshore and offshore Louisiana. An affiliate of Shell owns the remaining 36% interest in Poseidon.
- Odyssey. The Odyssey system is comprised of 12- to 20-inch diameter pipelines to deliver crude oil from developments in the eastern Gulf of Mexico to other pipelines and terminals onshore Louisiana. An affiliate of Shell owns the remaining 71% interest in Odyssey.
- Eugene Island. The Eugene Island system is comprised of a network of crude oil pipelines, the main pipeline of which is 20 inches in diameter, to deliver crude oil from developments in the central Gulf of Mexico to other pipelines and terminals onshore Louisiana. Other owners in Eugene Island include affiliates of Exxon Mobil, ConocoPhillips and Shell Oil Company.
- SEKCO Pipeline. SEKCO is a deepwater pipeline serving the Lucius crude oil and natural gas field located in the southern Keathley Canyon area of the Gulf of Mexico. SEKCO has crude oil transportation agreements with five Gulf of Mexico producers, including Anadarko U.S. Offshore Corporation, Exxon Mobil Corporation, Eni Petroleum US LLC, Petrobras America and Inpex Corporation. Those producers have dedicated their production from Lucius to that pipeline for the life of the reserves. We expect the SEKCO pipeline to also provide capacity for additional projects in the deepwater Gulf of Mexico in the future.

Table of Contents

- Shenzi Crude Oil. The Shenzi Crude Oil Pipeline gathers crude oil production from the Shenzi production field located in the Green Canyon area of the Gulf of Mexico offshore Louisiana for delivery to both our CHOPS and Poseidon pipeline systems.
- Allegheny Crude Oil. The Allegheny Crude Oil Pipeline connects the Allegheny and South Timbalier 316 platforms in the Green Canyon area of the Gulf of Mexico with the CHOPS and Poseidon pipelines.
- Marco Polo Crude Oil. The Marco Polo Crude Oil Pipeline transports crude oil from our Marco Polo crude oil platform to an interconnect with the Allegheny Crude Oil Pipeline in Green Canyon Block 164.
- Constitution Crude Oil. The Constitution Crude Oil Pipeline gathers crude oil from the Constitution, Caesar Tonga and Ticonderoga production fields located in the Green Canyon area of the Gulf of Mexico for delivery to either the CHOPS or Poseidon pipelines.

None of our offshore crude oil pipelines are rate regulated with the exception of Eugene Island, which is regulated by the FERC.

The table below reflects our interests in our operating offshore natural gas pipelines:

| Offshore natural gas pipelines | Operator | System Miles | Design Capacity (MMcf/day) (1) | Interest Owned | |
|---|---|---|---|---|---|
| Independence Trail | Genesis | 135 | 1,000 | 100 | % |
| High Island Offshore System | Genesis | 287 | 500 | 100 | % |
| Anaconda Gathering System | Genesis | 183 | 300 | 100 | % |
| Green Canyon Laterals | Genesis | 27 | 113 | Various (2) | |
| Manta Ray Offshore Gathering System | Enbridge | 237 | 800 | 25.7 | % |
| Nautilus System | Enbridge | 101 | 600 | 25.7 | % |
| Total | | 970 | 3,313 | | |

(1) Capacity figures presented represent 100% of the design capacity.

(2) We proportionately consolidate our undivided interest, which is 13.58%, in approximately 20 miles of the Green Canyon Lateral pipelines. The remainder of the laterals are wholly owned.

- Independence Trail. The Independence Trail pipeline transports natural gas from certain pipeline interconnects to the Tennessee Gas Pipeline at a pipeline interconnect on the West Delta 68 pipeline junction platform. Natural gas transported on the Independence Trail Pipeline can originate from production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico.
- High Island. The High Island Offshore System (HIOS) transports natural gas from producing fields located in the Galveston, Garden Banks, West Cameron, High Island and East Breaks areas of the Gulf of Mexico to interconnects with the Kinetica Energy Express. HIOS includes 201 miles of pipeline and eight pipeline junction and service platforms that are regulated by the FERC. In addition, this system included the 86-mile East Breaks Gathering System, which connects HIOS to the Hoover-Diana deepwater platform located in Alaminos Canyon Block 25.
- Anaconda. The Anaconda Gathering System gathers natural gas from producing fields located in the Green Canyon area of the Gulf of Mexico for delivery to the Nautilus System.
- Green Canyon. The Green Canyon Laterals represent a collection of small diameter pipelines that gather natural gas for delivery to HIOS and various other downstream pipelines.
- Manta Ray. The Manta Ray Offshore Gathering System gathers natural gas from producing fields located in the Green Canyon, Southern Green Canyon, Ship Shoal, South Timbalier and Ewing Bank areas of the Gulf of Mexico for delivery to numerous downstream pipelines, including the Nautilus System. This system includes three pipeline junction platforms.
- Nautilus. The Nautilus System connects the Anaconda Gathering system and Manta Ray Offshore Gathering System to the Neptune natural gas processing plant located in south Louisiana.

Offshore Hub Platforms

Offshore Hub platforms are typically used to interconnect the offshore pipeline network; provide an efficient means to perform pipeline maintenance; locate compression, separation and production handling equipment and similar assets; and conduct drilling operations during the initial development phase of a crude oil and natural gas property. The results of operations from offshore platform services are primarily dependent upon the level of commodity charges and/or demand-type

Table of Contents

fees billable to customers. Revenue from commodity charges is based on a fee per unit of volume delivered to the platform (typically per MMcf of natural gas or per barrel of crude oil) multiplied by the total volume of each product delivered. Demand-type fees are similar to firm capacity reservation agreements for a pipeline in that they are charged to a customer regardless of the volume the customer actually delivers to the platform. Contracts for platform services often include both demand-type fees and commodity charges, but demand-type fees generally expire after a contractually fixed period of time and in some instances may be subject to cancellation by customers.

The table below reflects our interests in our operating offshore hub platforms:

| Offshore hub platform | Operator | Water Depth (Feet) | Natural Gas Capacity (MMcf/day) (1) | Crude Oil Capacity (Bbls/day) (1) | Interest Owned |
|---|---|---|---|---|---|
| Marco Polo | Anadarko | 4,300 | 300 | 120,000 | 100 % |
| Garden Banks 72 (2) | Genesis | 518 | 216 | 36,000 | 54 % |
| East Cameron 373 | Genesis | 441 | 195 | 3,000 | 100 % |
| Total | | | 711 | 159,000 | |

(1) Capacity figures presented represent 100% of the design capacity.

(2) We proportionately consolidate our undivided interest in the Garden Banks 72 platform.

- Marco Polo. The Marco Polo platform, which is located in Green Canyon Block 608, processes crude oil and natural gas from production fields located in the South Green Canyon area of the Gulf of Mexico.
- Garden Banks. The Garden Banks 72 platform serves as a base for gathering deepwater production from the Garden Banks area of the Gulf of Mexico. This platform also serves as a junction platform for the CHOPS and Poseidon pipeline systems.
- East Cameron. The East Cameron 373 platform processes production from the Garden Banks and East Cameron areas of the Gulf of Mexico.

Customers

Due to the cost of finding, developing and producing crude oil properties in the deepwater regions of the Gulf of Mexico, most of our offshore pipeline customers are integrated crude oil companies and other large producers, and those producers desire to have longer-term arrangements ensuring that their production can access the markets. Usually, our offshore crude oil pipeline customers enter into buy-sell or other transportation arrangements, pursuant to which the pipeline acquires possession (and, sometimes, title) from its customer of the relevant production at a specified location (often a producer’s platform or at another interconnection) and redelivers possession (and title, if applicable) to such customer of an equivalent volume at one or more specified downstream locations (such as a refinery or an interconnection with another pipeline). Most of the production handled by our offshore pipelines is pursuant to life-of-reserve commitments that include both firm and interruptible capacity arrangements.

Revenues from customers of our offshore pipeline transportation segment did not account for more than ten percent of our consolidated revenues.

Competition

The principal competition for our offshore pipelines includes other crude oil and natural gas pipeline systems as well as producers who may elect to build or utilize their own production handling facilities. Our offshore pipelines 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. In addition, the ability of our offshore pipelines to access future reserves will be subject to our ability, or the producers’ ability, to fund the significant capital expenditures required to connect to the new production. In general, most of our offshore pipelines are not subject to regulatory rate-making authority, and the rates our offshore pipelines charge for services are dependent on the quality of the service required by the customer and the amount and term of the reserve commitment by that customer.

Sodium Minerals and Sulfur Services

Our Sodium Minerals and Sulfur Services segment consists of our legacy sulfur removal business, as well as those of our newly acquired Alkali Business as discussed in further detail below.

Table of Contents

## Alkali Business

Our Alkali Business is one of the leading producers of natural soda ash worldwide. We provide our soda ash to a variety of industries such as flat glass, container glass, detergent and chemical manufacturing. Soda ash, also known by its chemical name sodium carbonate ($Na_2CO_3$), is a highly valued raw material in the manufacture of glass due to its properties of lowering the melting point of silica in the batch. Soda ash is also valued by detergent manufacturers for its absorptive and water softening properties. We produce our products from trona, which we mine at two sites in the Green River Basin, Wyoming. The vast majority of the world's accessible trona reserves are located in the Green River Basin. According to historical production statistics, approximately one-quarter of global soda ash is produced from trona, with the remainder being produced synthetically, which requires chemical transformation of limestone and salt using a significantly higher amount of energy. Production of soda ash from trona is significantly less expensive than producing it synthetically. In addition, life-cycle analyses reveal that production from trona consumes less energy and produces less carbon dioxide and fewer undesirable by-products than synthetic production.

Our Alkali segment includes the following:

- Dry mining of trona ore underground at our Westvaco facility;
- Secondary recovery of trona from previously dry mined areas underground at our Westvaco and Granger facilities through solution mining;
- Processing of raw trona ore into soda ash and specialty sodium alkali products; and
- Marketing, sale and distribution of alkali products.

Our Alkali segment currently produces approximately 4 million tons of soda ash and downstream specialty products annually. All mining and processing activities related to our products take place in our facilities located in the Green River Basin of Wyoming, United States.

### Dry Mining of Trona Ore

Trona is dry mined underground at our Westvaco facility primarily through the operation of our single longwall mining machine. Longwall mining provides higher recovery rates leading to extended mine life compared to other dry mining techniques. Development of the "tunnels" necessary to access and ventilate our longwall is through room and pillar mining completed primarily by our fleet of borer miners. The ore is conveyed underground to two hoisting operations where it travels about 1,600 feet vertically to the surface and is either taken directly into the processing facilities or stored on outdoor stockpiles for future consumption.

### Secondary Recovery Solution Mining

We solution mine trona at both our Westvaco and Granger sites using secondary recovery techniques. Our secondary recovery mining starts with the recovery of water streams from our operations and non-trona solids ("insolubles") remaining from the processing of dry mined trona. The water and some insolubles are injected through a number of wells into the old dry mine workings at both our Westvaco and Granger sites. The insolubles settle out while the water travels through the old workings, dissolving trona that remained during previous dry mining. Multiple pumping systems are used to pump the enriched solution to the surface for processing.

### Processing of Trona into Finished Alkali Products

Our Sesqui and Mono plants, located at our Westvaco site, convert dry-mined trona into soda ash. Crushing, dissolution in water, filtration, and crystallization techniques are used to produce the desired final products. In the Mono process, the ore is calcined with heat, prior to dissolution, to convert the trona to soda ash by the removal of water and carbon dioxide. A final drying step using steam produces a dense soda ash product from the Mono process. In our Sesqui plant, the calcination is performed at the end of the process, producing a light density soda ash that is preferred in applications desiring increased absorptivity. The Sesqui process also has the ability to produce refined sodium sesquicarbonate (which we sell under the names S-Carb ® and Sesqui™) for use as a buffer in animal feed formulations and in cleaning and personal care applications.

Solution mined trona is converted into dense soda ash in our ELDM operation at the Westvaco site and at our Granger facility. The steps to produce soda ash are similar to the dry mined processes, except the crushing and dissolving steps are eliminated because the trona is already in a water solution as it leaves the mine.

Intermediate, semi-processed products are extracted from our soda ash processes at Westvaco at strategic locations for use as feedstocks for production of sodium bicarbonate and 50% caustic soda (NaOH).

Table of Contents

Marketing, Sale and Distribution of Alkali Products

We sell our alkali products to customers directly in the United States, Canada, the European Community, the European Free Trade Area and the South African Customs Union. We sell through ANSAC exclusively in all other markets. ANSAC is a nonprofit foreign sales association in which we and two other U.S. soda ash producers are members, whose purpose is to promote export sales of U.S. produced soda ash in conformity with the Webb-Pomerene Act.

All of our alkali products are shipped by rail and truck from our facilities in the Green River Basin. We operate a fleet of nearly 3,500 covered hopper cars which we use to deliver over 90% of the sales of alkali products from the Green River facilities, all of which are shipped via a single rail line owned and operated by Union Pacific Railroad. We lease these railcars from banks and leasing companies and from FMC Corporation under agreements with varying term-lengths. We recover costs of leasing through mileage credits paid under agreements with customers and carriers in accordance with established industry practices and government requirements.

We sell most of our Alkali products as soda ash. Soda ash is the only product we sell to ANSAC. Soda ash is highly valued by manufacturers of flat and container glass because it lowers the temperature of the batch in a glass furnace. It is also valued by detergent manufacturers for its absorptive qualities. Demand for soda ash in the United States has been relatively flat over the last five years. Sales of soda ash in rapidly developing economies have grown more rapidly as a growing middle class demands more products that use soda ash, such as glass for housing and autos and detergents for cleaning.

In addition, we also market sodium bicarbonate to private label manufacturers who package it for sale to retail grocery customers as baking soda. We also sell sodium bicarbonate to manufacturers of packaged baked goods and similar products. Animal feed is an important market for sodium bicarbonate, which is mixed with feed to increase the yield of dairy cows and improve the health of poultry and other livestock. Sodium bicarbonate is also sold to customers who use it in hemodialysis applications and as an active ingredient in pharmaceutical products.

Sulfur Removal Business

Our sodium minerals and sulfur services segment, through our legacy sulfur removal business, primarily (i) provides sulfur-extraction services to ten refining operations located mostly in Texas, Louisiana, Arkansas, Oklahoma, Montana and Utah, (ii) operates significant storage and transportation assets in relation to those services and (iii) sells NaHS and caustic soda to large industrial and commercial companies. Our sulfur removal services primarily involve processing refiners' high sulfur (or “sour”) gas streams that the refineries have generated from crude oil processing operations. Our process applies our proprietary technology, which uses large quantities of caustic soda (the primary raw material used in our process) to act as a scrubbing agent under prescribed temperature and pressure to remove sulfur. Sulfur removal in a refinery is a key factor in optimizing production of refined products such as gasoline, diesel and aviation fuel. Our sulfur removal technology returns a clean (sulfur-free) hydrocarbon stream to the refinery for further processing into refined products, and simultaneously produces NaHS. The resultant NaHS constitutes the sole consideration we receive for our sulfur removal services. A majority of the NaHS we receive is sourced from refineries owned and operated by large companies, including Phillips 66, CITGO, HollyFrontier, Calumet and Ergon. Our ten sulfur removal services contracts have an average remaining life of four and a half years. This includes the extended term of our renegotiated sulfur removal services contract with Phillips 66 at our Westlake, Louisiana facility, which now extends through 2026. The timing upon which these contracts renew vary based upon location and terms specified within each specific contract.

Our sodium minerals and sulfur services footprint includes NaHS and caustic soda terminals in the Gulf Coast, the Midwest, Montana, Utah, British Columbia and South America. In conjunction with our onshore facilities and transportation segment, we sell and deliver (via railcars, ships, barges and trucks) NaHS and caustic soda to approximately 150 customers. We believe we are one of the largest marketers of NaHS in North and South America. By minimizing our costs through utilization of our own logistical assets and leased storage sites, we believe we have a competitive advantage over other suppliers of NaHS. NaHS is used in the specialty chemicals business (plastic additives, dyes and personal care products), in pulp and paper business, and in connection with mining operations (nickel, gold and separating copper from molybdenum) as well as bauxite refining (aluminum). NaHS has also gained acceptance in environmental applications, including waste treatment programs requiring stabilization and reduction of heavy and toxic metals and flue gas scrubbing. Additionally, NaHS can be used for removing hair from hides at the beginning of the tannery process.

Caustic soda is used in many of the same industries as NaHS. Many applications require both chemicals for use in the same process. For example, caustic soda can increase the yields in bauxite refining, pulp manufacturing and in the recovery of copper, gold and nickel. Caustic soda is also used as a cleaning agent (when combined with water and heated) for process equipment and storage tanks at refineries.

Customers

We provide on-site sulfur removal services utilizing NaHS units at ten refining locations. Even though some of our customers have elected to own the sulfur removal facilities located at their refineries, we operate those facilities. We market all of our NaHS as well as small amounts of NaHS for a handful of third parties.

We sell our NaHS to customers in a variety of industries, with the largest customers involved in mining of base metals, primarily copper and molybdenum and the production of pulp and paper. We sell to customers in the copper mining industry in the western U.S., Canada and Mexico. We also export the NaHS to South America for sale to customers for mining in Peru and Chile. No sulfur removal customer or NaHS sales customer is responsible for more than ten percent of our consolidated revenues. Many of the industries that our NaHS customers are in (such as copper mining and the pulp and paper industry) participate in global markets for their products. As a result, this creates an indirect exposure for NaHS to global demand for the end products of our customers. Provisions in our service contracts with refiners allow us to adjust our sour gas processing rates (sulfur removal) to maintain a balance between NaHS supply and demand.

We sell caustic soda to many of the same customers who purchase NaHS from us, including pulp and paper manufacturers and customers in the copper mining industry. We also supply caustic soda to some of the refineries in which we operate for use in cleaning processing equipment.

Our natural soda ash is sold to a diverse customer base in the United States, Canada, the European Community, the European Free Trade Area and the South African Customs Union. Our Alkali Business sells exclusively through the American Natural Soda Ash Corporation, or ANSAC, in all other markets. ANSAC is a nonprofit foreign sales association in which our Alkali Business and two other U.S. soda ash producers are members. ANSAC is our Alkali Business' largest customer. Soda ash sold to ANSAC is later resold to other customers worldwide. Soda ash is utilized by our customers as basic building block for a number of ubiquitous products, including flat glass, container glass, dry detergent and a variety of chemicals and other industrial products.

Competition

The global soda ash market in which our Alkali Business operates is competitive. Competition is based on a number of factors such as price, favorable logistics and consistent customer service. In North America, primary competition is from other U.S.-based natural soda ash operations: Solvay Chemicals, Ciner Resources, L.P., Tata Chemicals Soda Ash Partners in Wyoming, and Searles Valley Minerals, in California. Because of the structural cost advantages of natural soda ash production in the United States, including lower raw material and energy requirements, imports have not been an important source of competition in North America. According to IHS, on average, the cash cost to produce material soda ash has been about half of the cost to produce synthetic soda ash. Sales of soda ash and specialty products outside of North America (principally through ANSAC) face competition from a variety of others, in most cases producers of soda ash using the synthetic method, but to a lesser extent producers of natural soda ash based in Turkey, China and Africa. Our Alkali Business' specialty Alkali products also experience significant competition from producers of sodium bicarbonate, such as Church & Dwight Co., Solvay Chemicals and Natural Soda LLC.

Soda ash is highly valued by manufacturers of flat and container glass because it lowers the temperature of the batch in a glass furnace. It is also valued by detergent manufacturers for its absorptive qualities. In addition, soda ash is used in paper production applications and other consumer and industrial applications. Demand for soda ash in the United States has been relatively flat over the last five years. Sales of soda ash in rapidly developing economies have grown more rapidly as a growing middle class demands more products that use soda ash, such as glass for housing and autos and detergents for cleaning.

ANSAC is our Alkali Business's largest customer, with total sales representing 32% of total sales in the segment. Apart from ANSAC, our sodium minerals and sulfur services segment is not dependent on any single or small group of customers, the loss of one of which would not have a material adverse effect on us.

Our competitors for the supply of NaHS consist primarily of parties who produce NaHS as a by-product of or an alternative to other sulfur derivative products, including fertilizers, pesticides, other agricultural products, plastic additives and lubricants. Typically our competitors for the supply of NaHS have only one location and they do not have the logistical infrastructure that we have to supply customers. These competitors often reduce NaHS production when demand for their alternative sulfur derivatives is high and increase NaHS production when demand for these alternatives is low. Also, they tend to supply less when prices and demand for elemental sulfur are higher and supply more NaHS when the price of elemental sulfur falls.

Demand for NaHS faces competition from alternative sulfidity management mediums such as sulfidic caustic, emulsified sulfur, salt cake and flake NaHS. Changes in the value, supply and/or demand of these alternative products can impact the volume and/or value of our NaHS sold.

Typically, our competitors for sulfur removal services include refineries themselves through the use of their sulfur removal processes.

Table of Contents

Our competitors for sales of caustic soda include manufacturers of caustic soda. These competitors supply caustic soda to our sodium minerals and sulfur services operations and support us in our third-party caustic soda sales. By utilizing our storage capabilities and having access to transportation assets, we sell caustic soda to third parties who gain efficiencies from acquiring both NaHS and caustic soda from one source.

Onshore Facilities and Transportation

We provide onshore facilities and transportation services to Gulf Coast crude oil refineries and producers through a combination of purchasing, transporting, storing, blending and marketing of crude oil and refined products (primarily fuel oil, asphalt, and other heavy refined products). In connection with these services, we utilize our increasingly integrated portfolio of logistical assets consisting of pipelines, trucks, terminals, railcars and barges. The increasingly integrated nature of our onshore facilities and transportation assets is particularly evident in certain of our recently completed growth initiatives in areas such as Louisiana and Texas. Our crude oil related services include gathering crude oil from producers at the wellhead, transporting crude oil by gathering line, truck, railcar and barge to pipeline injection points, transporting crude oil for our gathering and marketing operations and for other shippers on our pipelines and marketing crude oil to refiners. Not unlike our crude oil operations, we also gather refined products from refineries, transport refined products via pipeline, truck, railcar and barge, and sell refined products to customers in wholesale markets. For certain of these services, we generate fee-based income related to the transportation services provided. In some cases, we also profit from the difference between the price at which we re-sell the crude oil and petroleum products less the price at which we purchase the crude oil and products, minus the associated costs of aggregation and transportation.

Our crude oil onshore facilities and transportation operations are concentrated in Texas, Louisiana, Alabama, Florida and Mississippi. These operations help to ensure (among other things) a base supply source for our crude oil pipeline systems, refinery customers and other shippers while providing our producer customers with a market outlet for their production. We attempt to limit our direct commodity price risk in our onshore facilities and transportation segment by utilizing back-to-back purchases and sales, matching sale and purchase volumes on a monthly basis and hedging unsold volumes (primarily with NYMEX derivatives to offset the remaining price risk); however, we cannot completely eliminate commodity price risks. By utilizing our network of pipelines, trucks, railcars, barges, and terminals, we are able to provide transportation related services to, and in many cases back-to-back gathering and marketing arrangements with, crude oil refiners and producers. Additionally, our crude oil gathering and marketing expertise and knowledge base provide us with an ability to capitalize on opportunities that arise from time to time in our market areas. We gather and market approximately 45,000 barrels per day of crude oil, much of which is produced from large resource basins throughout Texas and the Gulf Coast. Our crude oil pipelines transport many of these barrels, as well barrels for third party producers and refiners to which we charge fees for our transportation services. Given our network of terminals, we also have the ability to store crude oil during periods of contango (crude oil prices for future deliveries are higher than for current deliveries) for delivery in future months. When we purchase and store crude oil during periods of contango, we attempt to limit direct commodity price risk by simultaneously entering into a contract to sell the inventory in a future period, either with a counterparty or in the crude oil futures market. The most substantial component of the costs we incur while aggregating crude oil and petroleum products relates to operating our fleet of owned and leased trucks and railcars and incurring transportation related costs.

Onshore Crude Oil Pipelines

Through the onshore pipeline systems and related assets we own and operate, we transport crude oil for our gathering and marketing operations and for other shippers pursuant to tariff rates regulated by FERC or the Railroad Commission of Texas, or TXRRC. Accordingly, we offer transportation services to any shipper of crude oil, if the products tendered for transportation satisfy the conditions and specifications contained in the applicable tariff. Pipeline revenues are a function of the level of throughput and the particular point where the crude oil is injected into the pipeline and the delivery point. We also may earn revenue from pipeline loss allowance volumes. In exchange for bearing the risk of pipeline volumetric losses, we deduct volumetric pipeline loss allowances and crude oil quality deductions. Such allowances and deductions are offset by measurement gains and losses. When our actual volume losses are less than the related allowances and deductions, we recognize the difference as income and inventory available for sale valued at the market price for the crude oil.

The margins from our onshore crude oil pipeline operations are generated by the difference between the sum of revenues from regulated published tariffs and pipeline loss allowance revenues and the fixed and variable costs of operating and maintaining our pipelines.

We own and operate four onshore common carrier crude oil pipeline systems: the Texas System, the Jay System, the Mississippi System, and the Louisiana System.

Table of Contents

| | Texas System | Jay System | Mississippi System | Louisiana System |
|---|---|---|---|---|
| Product | Crude Oil | Crude Oil | Crude Oil | Crude Oil<br>Intermediates<br>Refined Products |
| Interest Owned | 100% | 100% | 100% | 100% |
| Design Capacity (Bbls/day) | Existing 8" - 60,000<br>Looped 18" - 275,000 | 150,000 | 45,000 | 350,000 |
| 2018 Throughput (Bbls/day) | 33,303 | 14,036 | 6,359 | 159,754 |
| System Miles | 47 | 135 | 220 | 51 |
| Approximate owned tankage storage capacity (Bbls) | 1,100,000 | 230,000 | 247,500 | 330,000 |
| Location | Hastings Junction, TX to Webster, TX<br><br>Texas City, TX to Webster, TX | Southern AL/FL to Mobile, AL | Soso, MS to Liberty, MS | Port Hudson, LA to Baton Rouge, LA<br><br>Baton Rouge, LA to Port Allen, LA |
| Rate Regulated | FERC/TXRRC | FERC | FERC | FERC |

- Texas System. Our Texas System transports crude oil from Hastings Junction (south of Houston) to several delivery points near Houston, Texas (including our Webster, Texas facility). This system also takes delivery of crude oil volumes at Texas City (which includes the capability of receiving various Gulf of Mexico pipeline volumes) for delivery to our Webster, Texas facility, which ultimately connects to other crude oil pipelines. We earn a tariff for our transportation services, with the tariff rate per barrel of crude oil varying with the distance from injection point to delivery point.
- Jay System. Our Jay System provides crude oil shippers access to refineries, pipelines and storage near Mobile, Alabama. That system also includes gathering connections to approximately 43 wells, additional crude oil storage capacity of 20,000 barrels in the field, an interconnect with our Walnut Hill rail facility, a delivery connection to a refinery in Alabama and an interconnection to another common carrier pipeline that delivers crude oil into Mississippi.
- Mississippi System. Our Mississippi System provides shippers of crude oil in Mississippi indirect access to refineries, pipelines, storage, terminals and other crude oil infrastructure located in the Midwest. That system is adjacent to several crude oil fields that are in various phases of being produced through tertiary recovery strategy, including $CO_2$ injection and flooding. We provide transportation services on our Mississippi pipeline through an “incentive” tariff which provides that the average rate per barrel that we charge during any month decreases as our aggregate throughput for that month increases above specified thresholds.
- Louisiana System. Our Louisiana System transports crude oil from Port Hudson to our Baton Rouge Scenic Station rail unloading facility and continues downstream to the Anchorage Tank Farm servicing Exxon Mobil Corporation's Baton Rouge refinery. This refinery is one of the largest refinery complexes in North America, with more than 500,000 barrels per day of refining capacity. Our Louisiana system also connects the Anchorage Tank Farm to our Port of Baton Rouge Terminal (which was also built to service Exxon's Baton Rouge refinery), allowing bidirectional flow of crude oil, intermediates and refined products between the Anchorage Tank Farm and this terminal via a dedicated crude pipeline and a dedicated intermediates pipeline.

This pipeline system serves as a key asset in our increasingly integrated Baton Rouge area midstream infrastructure, which also includes terminal and rail facilities as discussed previously.

Table of Contents

Other Onshore Facilities and Transportation Operations

We own four operational crude oil rail unloading facilities located in Baton Rouge, Louisiana; Raceland, Louisiana; Walnut Hill, Florida; and Natchez, Mississippi which provide synergies to our existing asset footprint. We generally earn a fee for loading or unloading railcars at these facilities. Three of these facilities, our Baton Rouge, Louisiana, Raceland, Louisiana, and Walnut Hill, Florida facilities are directly connected to our existing integrated crude oil pipeline and terminal infrastructure. See further discussion of these facilities above.

Within our onshore facilities and transportation business segment, we employ many types of logistically flexible assets. These assets include approximately 200 trucks, 300 trailers, 404 railcars, and terminals and other tankage with 4.6 million barrels of leased and owned storage capacity in multiple locations along the Gulf Coast, accessible by pipeline, truck, rail or barge, in addition to tankage related to our crude oil pipelines, previously mentioned. Our leased railcars consist of approximately 7 refined product railcars and 397 crude oil railcars.

Our refined products onshore facilities and transportation operations are concentrated in the Gulf Coast region, principally Texas and Louisiana. Through our footprint of owned and leased pipelines, trucks, leased railcars, terminals and barges, we are able to provide Gulf Coast area refineries with transportation services as well as market outlets for certain heavy refined products. We primarily engage in the transportation and supply of fuel oil, asphalt, and other heavy refined products to our customers in wholesale markets. We have the ability from time to time to obtain various grades of refined products from our refinery customers and blend them to meet the requirements of our other market customers. However, because our refinery customers may choose to manufacture such refined products based on a number of economic and operating factors, we cannot predict the timing of contribution margins related to our blending services.

CO2 Pipelines

We transport $CO_2$ on our Free State pipeline for a fee and we lease our Northeast Jackson Dome Pipeline System, or NEJD System, for a fee.

| | Free State Pipeline |
|---|---|
| Product | $CO_2$ |
| Interest owned | 100% |
| System miles | 86 |
| Pipeline diameter | 20" |
| Location | Jackson Dome near Jackson, MS to East Mississippi |
| Rate Regulated | No |

Our Free State pipeline extends from $CO_2$ source fields near Jackson, Mississippi to crude oil fields in eastern Mississippi. We have a transportation services agreement through 2028 related to our Free State pipeline with a single shipper who has the right to use 100% of that pipeline's capacity.

Our NEJD System transports $CO_2$ to tertiary crude oil recovery operations in southwest Mississippi. We have leased that pipeline to an affiliate of the shipper on our Free State pipeline through 2028. Our NEJD lessee is responsible for all operations and maintenance on that system and will bear and assume substantially all obligations and liabilities with respect to that system.

Customers

Our onshore facilities and transportation business encompasses numerous refiners and hundreds of producers, for which we provide transportation related services, as well as gather from and market to crude oil and refined products. During 2018, no onshore facilities and transportation customers generated over 10% of our consolidated revenue.

Competition

In our crude oil onshore facilities and transportation operations, we compete with other midstream service providers and regional and local companies who may have significant market share in the respective areas in which they operate. Competition among common carrier pipelines is based primarily on posted tariffs, quality of customer service and proximity to refineries, production and connecting pipelines. We believe that high capital costs, tariff regulation and the cost of acquiring rights-of-way make it unlikely that other competing pipeline systems, comparable in size and scope to our onshore pipelines, will be built in the same geographic areas in the near future. In addition, as the majority of our onshore pipelines directly serve refineries we believe that these pipelines are not subject to the same competitive pressures as those tied directly to crude oil

Table of Contents

production. Additionally, the shipper on our Free State pipeline is required to use our Free State pipeline for any transportation of $CO_2$ within a dedicated area.

In our refined products onshore facilities and transportation operations, we compete primarily with regional companies. See "Marine Transportation - Competition" for additional discussion of our competitors. Competitive factors in our onshore facilities and transportation business include price, relationships with customers, range and quality of services, knowledge of products and markets, availability of trade credit and capabilities of risk management systems.

Marine Transportation

Our marine transportation segment consists of (i) our inland marine fleet which transports heavy refined petroleum products, including asphalt, principally serving refineries and storage terminals along the Gulf Coast, Intracoastal Canal and western river systems of the U.S., principally along the Mississippi River and its tributaries, (ii) our offshore marine fleet which transports crude oil and refined petroleum products, principally serving refineries and storage terminals along the Gulf Coast, Eastern Seaboard, Great Lakes and Caribbean, and (iii) our modern double-hulled, Jones Act qualified tanker M/T American Phoenix which is currently under charter serving a customer along the Gulf Coast until 2020. The below table includes operational information relating to our marine transportation fleet:

| | Inland | Offshore | American Phoenix |
|---|---|---|---|
| Aggregate Fleet Design Capacity (Bbls) (in thousands) | 2,285 | 884 | 330 |
| Individual Vessel Capacity Range (Bbls) (in thousands) (1) | 23-39 | 65-135 | 330 |
| | | | |
| Number of: | | | |
| Push/Tug Boats | 33 | 9 | — |
| Barges | 82 | 9 | — |
| Product Tankers | — | — | 1 |

(1) Represents capacity per barge ranges on our inland and offshore barge, as well as the capacity of our M/T American Phoenix.

Customers

Our marine customers are primarily refiners and some large energy companies. Our M/T American Phoenix is currently operating under a long term charter into 2020 with a large refining customer. We are a provider of transportation services for our customers and, in almost all cases, do not assume ownership of the products we transport. Marine transportation services are conducted under term contracts, some of which have renewal options for customers with whom we have traditionally had long-standing relationships, as well as spot contracts. Most have been our customers for many years and we generally anticipate continued relationships; however, there is no assurance that any individual contract will be renewed.

A term contract is an agreement with a specific customer to transport cargo from a designated origin to a designated destination at a set rate (affreightment) or at a daily rate (time charter). The rate may or may not escalate during the term of the contract; however, the base rate generally remains constant and contracts often include escalation provisions to recover changes in specific costs such as fuel. Time charters, which insulate us from revenue fluctuations caused by weather and navigational delays and temporary market declines, represented over 95% of our marine transportation revenues under term contracts during 2018, 2017 and 2016. A spot contract is an agreement with a customer to move cargo from a specific origin to a designated destination for a rate negotiated at the time the cargo movement takes place. Spot contract rates are at the current "market" rate and are subject to market volatility. We typically maintain a higher mix of term contracts to spot contracts to provide a predictable revenue stream while maintaining spot market exposure to take advantage of new business opportunities and existing customers' peak demands. During 2018, 2017 and 2016, approximately 62%, 64% and 62%, respectively, of our marine transportation revenues were from term contracts and 38%, 36% and 38%, respectively, were from spot contracts.

Revenues from customers of our marine transportation segment did not account for more than ten percent of our consolidated revenues.

Competition

Our competitors for the marine transportation of crude oil and heavy refined petroleum products are both midstream MLPs with marine transportation divisions, along with companies that are in the business of solely marine transportation operations. Competition among common marine carriers is based on a number of factors including proximity to production, refineries and connecting infrastructures, customer service, and transportation pricing.

Table of Contents

Our marine transportation segment also competes with other modes of transporting crude oil and heavy refined petroleum products, including pipeline, rail and trucking operations. Each such mode of transportation has different advantages and disadvantages, which often are fact and circumstance dependent. For example, without requiring longer-term economic commitments from shippers, marine and truck transportation can offer shippers much more flexibility to access numerous markets in multiple directions (i.e., pipelines tend to flow in a single direction and are geographically limited by their receipt and delivery points with other pipelines and facilities), and marine transportation offers shippers certain economies of scale as compared to truck transportation. In addition, due to construction costs and timing considerations, marine and truck transportation can provide cost effective and immediate services to a nascent producing region, whereas new pipelines can be very expensive and time consuming to construct and may require shippers to make longer-term economic commitments, such as take-or-pay commitments. On the other hand, in mature developed areas serviced by extensive, multi-directional pipelines, with extensive connections to various market, pipeline transportation may be preferred by shippers, especially if shippers are willing to make longer-term economic commitments, such as take-or-pay commitments.

Credit Exposure

Due to the nature of our operations, a disproportionate percentage of our trade receivables constitute obligations of refiners, large oil producers and integrated oil companies. This energy industry concentration has the potential to affect our overall exposure to credit risk, either positively or negatively, in that our customers could be affected by similar changes in economic, industry or other conditions. However, we believe that the credit risk posed by this industry concentration is offset by the creditworthiness of our specific customer base in the context of our specific transactions as well as other factors, including the strategic nature of certain of our assets and relationships and our credit procedures. Our portfolio of accounts receivable is generally comprised in large part of obligations of refiners, integrated and large independent oil and natural gas producers, and mining and other industrial companies that purchase NaHS and soda ash, most of which have stable payment histories. The credit risk related to contracts that are traded on the NYMEX is limited due to the daily cash settlement procedures and other NYMEX requirements.

When we market crude oil, petroleum products, NaHS, soda ash and provide transportation and other services, we must determine the amount, if any, of the line of credit we will extend to any given customer. We have established procedures to manage our credit exposure, including initial credit approvals, credit limits, collateral requirements and rights of offset. Letters of credit, prepayments and guarantees are also utilized to limit credit risk to ensure that our established credit criteria are met. We use similar procedures to manage our exposure to our customers in the offshore pipeline transportation and marine transportation segments.

As a result of our activities in the Gulf of Mexico and onshore (including our Alkali Business), our largest customers include Shell, Exxon Mobil Corporation, BP PLC, Phillips 66, Trafigura, Anadarko Petroleum Corporation and ANSAC.

Employees

To carry out our business activities, we employed approximately 2,100 employees at December 31, 2018. We believe that relationships with our employees are good.

Regulation

Pipeline Rate and Access Regulation

The rates and the terms and conditions of service of our interstate common carrier pipeline operations are subject to regulation by FERC under the Interstate Commerce Act, or ICA. Under the ICA, rates must be “just and reasonable,” and must not be unduly discriminatory or confer any undue preference on any shipper. FERC regulations require that oil pipeline rates and terms and conditions of service for regulated pipelines be filed with FERC and posted publicly. Effective January 1, 1995, FERC promulgated rules simplifying and streamlining the ratemaking process. Previously established rates were “grandfathered,” limiting the challenges that could be made to existing tariff rates. Increases from grandfathered rates of interstate oil pipelines are currently regulated by FERC primarily through an index methodology, whereby a pipeline is allowed to change its rates based on the year-to-year change in an index. Under FERC regulations, we are able to change our rates within prescribed ceiling levels that are tied to the Producer Price Index for Finished Goods. Rate increases made pursuant to the index will be subject to protest, but such protests must show that the rate increase resulting from application of the index is substantially in excess of the applicable pipeline’s

increase in costs.
In addition to the index methodology, FERC allows for rate changes under three other methods—cost-of-service, competitive market showings and agreements between shippers and the oil pipeline company that the rate is acceptable, or Settlement Rates. The pipeline tariff rates on our Mississippi, Jay, Louisiana, and Wyoming Systems are either rates that are subject to change under the index methodology or Settlement Rates. None of our tariffs have been subjected to a protest or complaint by any shipper or other interested party.

Table of Contents

Our offshore pipelines, with the exception of our Eugene Island pipeline, are neither interstate nor common carrier pipelines. However, these pipelines are subject to federal regulation under the Outer Continental Shelf Lands Act, which requires all pipelines operating on or across the outer continental shelf to provide nondiscriminatory transportation service.

Our intrastate common carrier pipeline operations in Texas are subject to regulation by the Railroad Commission of Texas. The applicable Texas statutes require that pipeline rates and practices be reasonable and non-discriminatory and that pipeline rates provide a fair return on the aggregate value of the property of a common carrier, after providing reasonable allowance for depreciation and other factors and for reasonable operating expenses. Although no assurance can be given that the tariffs we charge would ultimately be upheld if challenged, we believe that the tariffs now in effect can be sustained.

Our $CO_2$ pipelines are subject to regulation by the state agencies in the states in which they are located.

Marine Regulations

Maritime Law. The operation of towboats, tugboats, barges, vessels and marine equipment create maritime obligations involving property, personnel and cargo and are subject to regulation by the U.S. Coast Guard, or USCG, the Environmental Protection Agency, or EPA, the Department of Homeland Security, or DHS, federal laws, state laws and certain international conventions under General Maritime Law. These obligations can create risks which are varied and include, among other things, the risk of collision and allision, which may precipitate claims for personal injury, cargo, contract, pollution, third-party claims and property damages to vessels and facilities. Routine towage operations can also create risk of personal injury under the Jones Act and General Maritime Law, cargo claims involving the quality of a product and delivery, terminal claims, contractual claims and regulatory issues. Federal regulations also require that all tank barges engaged in the transportation of oil and petroleum in the U.S. be double hulled. All of our barges are double-hulled.

All of our barges are inspected by the USCG and carry certificates of inspection. All of our towboats and tugboats are certificated by the USCG. Most of our vessels are built to American Bureau of Shipping, or ABS, classification standards and in some instances are inspected periodically by ABS to maintain the vessels in class standards. The crews we employ aboard vessels, including captains, pilots, engineers, tankermen and ordinary seamen, are documented by the USCG.

We are required by various governmental agencies to obtain licenses, certificates and permits for our vessels depending upon such factors as the cargo transported, the waters in which the vessels operate and other factors. We are of the opinion that our vessels have obtained and can maintain all required licenses, certificates and permits required by such governmental agencies for the foreseeable future.

Jones Act: The Jones Act is a federal law that restricts maritime transportation between locations in the U.S. to vessels built and registered in the U.S. and owned and manned by U.S. citizens. We are responsible for monitoring the ownership of our subsidiary that engages in maritime transportation and for taking any remedial action necessary to insure that no violation of the Jones Act ownership restrictions occurs. Jones Act requirements significantly increase operating costs of U.S.-flag vessel operations compared to foreign-flag vessel operations. Further, the USCG and ABS maintain the most stringent regime of vessel inspection in the world, which tends to result in higher regulatory compliance costs for U.S.-flag operators than for owners of vessels registered under foreign flags or flags of convenience. The Jones Act and General Maritime Law also provide damage remedies for crew members injured in the service of the vessel arising from employer negligence or vessel unseaworthiness.

Merchant Marine Act of 1936: The Merchant Marine Act of 1936 is a federal law providing that, upon proclamation by the president of the U.S. of a national emergency or a threat to the national security, the U.S. Secretary of Transportation may requisition or purchase any vessel or other watercraft owned by U.S. citizens (including us, provided that we are considered a U.S. citizen for this purpose). If one of our tow boats or barges were purchased or requisitioned by the U.S. government under this law, we would be entitled to be paid the fair market value of the vessel in the case of a purchase or, in the case of a requisition, the fair market value of charter hire. However, if one of our tow boats is requisitioned or purchased and its associated barge or barges are left idle, we would not be entitled to receive any compensation for the lost revenues resulting from the idled barges. We also would not be entitled to be compensated for any consequential damages we suffer as a result of the requisition or purchase of any of our tow

boats or barges.
Security Requirements: The Maritime Transportation Security Act of 2002 requires, among other things, submission to and approval by the USCG of vessel and waterfront facility security plans, or VSP. Our VSP's have been approved and we are operating in compliance with the plans for all of its vessels and that are subject to the requirements, whether engaged in domestic or foreign trade.
Railcar Regulation
We operate a number of railcar loading and unloading facilities and lease a significant number of railcars. Our railcar operations are subject to the regulatory jurisdiction of the Federal Railroad Administration of the DOT, the Occupational Safety

Table of Contents

and Health Administration, or OSHA, as well as other federal and state regulatory agencies. We believe that our railcar operations are in substantial compliance with all existing federal, state and local regulations.

DOT and OSHA have jurisdiction under several federal statutes over a number of safety and health aspects of rail operations, including the transportation of hazardous materials. State agencies regulate some aspects of rail operations with respect to health and safety in areas not otherwise preempted by federal law.

Regulation of the Mining Industry in the United States

We have the right to mine trona through leases we hold from the U.S. Federal government, the State of Wyoming and an affiliate of Anadarko Petroleum (“Anadarko”). Our leases with the U.S. government are issued under the provisions of the Mineral Leasing Act of 1920 (30 U.S.C. 18 et. Seq.) and are administered by the U.S. Bureau of Land Management (“BLM”) and our leases with the state of Wyoming are issued under Wyoming Statutes 36-6-101 et. seq. Anadarko is the successor to rights originally granted to the Union Pacific Railroad in connection with the construction of the first transcontinental railroad in North America. For more information please see discussion of Mining and Mineral Tenure in Item 1 below.

We pay royalties to the BLM, the State of Wyoming and Anadarko. These royalties are calculated based upon the gross value of soda ash and related products at a certain stage in the mining process. We are obligated to pay minimum royalties or annual rentals to our lessors regardless of actual sales and in the case of Anadarko to pay royalties in advance based on a formula based on the amount of trona produced and sold in the previous year which is then credited against production royalties owed. The royalty rates we pay to our lessors may change upon our renewal of such leases; however, we anticipate being able to renew all material leases at the appropriate time. In the past, the U.S. Congress has passed legislation to cap royalties collected by BLM at a rate lower than the rate stated in our federal leases.

Our mining operations in Wyoming are subject to mine permits issued by the Land Quality Division of the Wyoming Department of Environmental Quality (“WDEQ”). WDEQ imposes detailed reclamation obligations on us as a holder of mine permits. As of December 31, 2018, the amount of our reclamation bond was approximately $80 million. The amount of the bond is subject to change based upon periodic re-evaluation by WDEQ.

The health and safety of our employees working underground and on the surface are subject to detailed regulation. The safety of our operations at Westvaco are regulated by the U.S. Mine Safety and Health Administration (“MSHA”) and our Granger Facility by the Wyoming Occupational Safety and Health Administration (“Wyoming OSHA”). MSHA administers the provisions of the Federal Mine Safety and Health Act of 1977 and enforces compliance with that statute’s mandatory safety and health standards. As part of MSHA’s oversight, representatives perform at least four unannounced inspections (approximately once quarterly) each year at Westvaco. Wyoming OSHA regulates the health and safety of non-mining operations under a plan approved by the U.S. Occupational Health and Safety Administration. When our Granger facility was restarted in 2009 on solution mine feed (i.e., without any miners working underground), Wyoming OSHA assumed responsibility for the facility.

Regulation of Finished Product Manufacturing

Our business is subject to extensive regulation by federal, state, local and foreign governments. Governmental authorities regulate the generation and treatment of waste and air emissions at our operations and facilities. We also comply with worldwide, voluntary standards developed by the International Organization for Standardization (“ISO”), a nongovernmental organization that promotes the development of standards and serves as a bridging organization for quality standards, such as ISO 9001:2015 for quality management and ISO 22000 for food safety management.

Several of the production operations in our Alkali Business are subject to regulation by the U.S. Food and Drug Administration (“FDA”). Our sodium bicarbonate plant is a registered facility for the production of food and pharmaceutical grade ingredients and we comply with strict Current Good Manufacturing Practice (“CGMP”) requirements in our operations. The U.S. Food Safety Modernization Act requires that parts of our facility that produce animal nutrition products comply with new more rigorous manufacturing standards. We believe that we materially comply with requirements currently in effect and have a program in place to maintain such compliance. We also comply with industry standards developed by various private organizations such as U.S. Pharmacopeia, Organic Materials Review Institute and the Orthodox Union. Alkali has also sought and received certification of its Wyoming facilities under ISO.9001:2015.

Environmental Regulations

General

We are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may (i) require the acquisition of and compliance with permits for regulated activities, (ii) limit or prohibit operations on environmentally sensitive lands such as wetlands or wilderness area, seismically sensitive areas, or areas inhabited by endangered or threatened species, (iii) result in capital expenditures to limit or prevent emissions or discharges, and (iv) place burdensome restrictions on our operations, including the management and disposal of wastes. Failure to comply with these laws and regulations may result in the

Table of Contents

assessment of administrative, civil and criminal penalties, including the assessment of monetary penalties, the imposition of investigatory and remedial obligations, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and the issuance of orders enjoining future operations or imposing additional compliance requirements. Changes in environmental laws and regulations occur frequently, typically increasing in stringency through time, and any changes that result in more stringent and costly operating restrictions, emission control, waste handling, disposal, cleanup and other environmental requirements have the potential to have a material adverse effect on our operations. While we believe that we are in substantial compliance with current environmental laws and regulations and that continued compliance with existing requirements will not materially affect us, there is no assurance that this trend will continue in the future. Revised or new additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and cash flows.

Hazardous Substances and Waste Handling

The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, or CERCLA, also known as the "Superfund" law, and analogous state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons. These persons include current owners and operators of the site where a release of hazardous substances occurred, prior owners or operators that owned or operated the site at the time of the release of hazardous substances, and companies that disposed or arranged for the disposal of the hazardous substances found at the site. We currently own or lease, and have in the past owned or leased, properties that have been in use for many years with the gathering and transportation of hydrocarbons including crude oil and other activities that could cause an environmental impact. Persons deemed "responsible persons" under CERCLA may be subject to strict and joint and several liability for the costs of removing or remediating previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), 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 the costs they incur from the responsible classes of persons. 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.

We also may incur liability under the Resource Conservation and Recovery Act, as amended, or RCRA, and analogous state laws which impose requirements and also liability relating to the management and disposal of solid and hazardous wastes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA's hazardous waste regulations. However, it is possible that these wastes, which could include wastes currently generated during our operations, will in the future be designated as "hazardous wastes" and, therefore, be subject to more rigorous and costly disposal requirements. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain crude oil and natural gas exploration and production wastes as "hazardous wastes." Also, in December 2016, the EPA agreed in a consent decree to review its regulation of oil and gas waste. It has until March 2019 to determine whether any revisions are necessary. Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

We believe that we are in substantial compliance with the requirements of CERCLA, RCRA and related state and local laws and regulations, and that we hold all necessary and up-to-date permits, registrations and other authorizations required under such laws and regulations. Although we believe that the current costs of managing our wastes as they are presently classified are reflected in our budget, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Water Discharges

The Federal Water Pollution Control Act, as amended, also known as the "Clean Water Act," and analogous state laws impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including crude oil, into navigable waters of the U.S., as well as state waters. Permits must be obtained to discharge pollutants into these waters. Spill prevention, control and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. The Clean Water Act and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. On June 29, 2015, the EPA and the U.S. Army Corps of Engineers, or Corps, jointly promulgated final rules redefining the scope of waters protected under the Clean Water Act. To the extent the rules expand the range of properties subject to the Clean Water Act's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

Also, on June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. In addition, the Clean

Table of Contents

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. These permits may require us to monitor and sample the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions.

The Oil Pollution Act is the primary federal law for oil spill liability. The Oil Pollution Act contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must develop and maintain facility response contingency plans and maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The Oil Pollution Act subjects owners of facilities to strict liability that, in some circumstances, may be joint and several for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters.

Noncompliance with the Clean Water Act or the Oil Pollution Act may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations. We believe we are in material compliance with each of these requirements.

Air Emissions

The Federal Clean Air Act, or CAA, as amended, and analogous state and local laws and regulations restrict the emission of air pollutants, and impose permit requirements and other obligations. Regulated emissions occur as a result of our operations, including the handling or storage of crude oil and other petroleum products. Both federal and state laws impose substantial penalties for violation of these applicable requirements. Accordingly, our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, revocation or suspension of necessary permits and, potentially, criminal enforcement actions.

On August 16, 2012, the EPA published final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA’s rule package includes New Source Performance standards to address emissions of sulfur dioxide and volatile organic compounds and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rules seek to achieve a 95% reduction in volatile organic compounds emitted by requiring the use of reduced emission completions or “green completions” on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of the requests for reconsideration. In particular, on May 12, 2016, the EPA amended its regulations to impose new standards for methane and volatile organic compounds emissions for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas sector. However, in a March 28, 2017 executive order, President Trump directed the EPA to review the 2016 regulations and, if appropriate, to initiate a rulemaking to rescind or revise them consistent with the stated policy of promoting clean and safe development of the nation’s energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production. On June 16, 2017, the EPA published a proposed rule to stay for two years certain requirements of the 2016 regulations, including fugitive emission requirements. These standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions.

NEPA

Under the National Environmental Policy Act, or NEPA, a federal agency, commonly in conjunction with a current permittee or applicant, may be required to prepare an environmental assessment or a detailed environmental impact statement before taking any major action, including issuing a permit for a pipeline extension or addition that would affect the quality of the environment. Should an environmental impact statement or environmental assessment be required for any proposed pipeline extensions or additions, NEPA may prevent or delay construction or alter the proposed location, design or method of construction.

Endangered Species Act

The federal Endangered Species Act and analogous state statutes restrict activities that may adversely affect endangered and threatened species or their habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act, though, in December 2017, the U.S. Fish and Wildlife Service provided guidance limiting the reach of the Act. The designation of previously unidentified endangered or threatened species in areas where we operate could cause us to incur additional costs or become subject to operating delays, restrictions or bans.

Table of Contents

Climate Change

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. These findings served as a statutory prerequisite for EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the CAA. The EPA also adopted two sets of related rules, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources of emissions such as power plants or industrial facilities. The EPA finalized the motor vehicle rule in April 2010 and it became effective in July 2010. The EPA adopted the stationary source rule, also known as the "Tailoring Rule," in May 2010, and it became effective in January 2011. The tailoring rule established new GHG emissions thresholds that determine when stationary sources must obtain permits under the PSD and Title V programs of the Clean Air Act. On June 23, 2014, in Utility Air Regulatory Group v. EPA ("UARG v. EPA"), the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD and Title V programs. On August 26, 2016, the EPA proposed changes needed to bring the EPA's air permitting regulations in line with the Supreme Court's decision on GHG permitting. The proposed rule was published in the Federal Register on October 3, 2016 and the public comment period closed on December 16, 2016.

Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., beginning in 2011 for emissions occurring in 2010. Further, in November 2010, the EPA expanded its existing GHG reporting rule to include onshore and offshore crude oil and natural gas production and onshore processing, transmission, storage and distribution facilities, which may include certain of our facilities, beginning in 2012 for emissions occurring in 2011. In October 2015, the EPA amended the GHG reporting rule to add the reporting of GHG emissions from gathering and boosting systems, completions and workovers of crude oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines. As a result of this continued regulatory focus, future GHG regulations of the crude oil and natural gas industry remain a possibility.

Further, the U.S. Congress has from time to time considered various proposals to reduce GHG emissions, and almost half of the states, either individually or through multi-state regional initiatives, have already taken legal measures to reduce GHG emissions, primarily through the planned development of GHG emission inventories and/or GHG cap-and-trade programs. The net effect of this legislation is to impose increasing costs on the combustion of carbon-based fuels such as crude oil, refined petroleum products and natural gas. Our compliance with any future legislation or regulation of GHGs, if it occurs, may result in materially increased compliance and operating costs.

In addition, in December 2015, the United States participated in the 21st Conference of the Parties (COP-21) of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature, and to conserve and enhance sinks and reservoirs of GHGs. The Agreement went into effect on November 4, 2016. The Agreement establishes a framework for the parties to cooperate and report actions to reduce GHG emissions. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement, and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. The Paris Agreement sets forth a specific exit process, whereby a party may not provide notice of its withdrawal until three years from the effective date, with such withdrawal taking effect one year from such notice. It is not clear what steps the Trump Administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

Legislative efforts or related implementation regulations that regulate or restrict emissions of GHGs in areas that we conduct business could adversely affect the demand for the products that we transport, store and distribute and, depending on the particular program adopted, could increase our costs to operate and maintain our facilities by requiring that we, among other things, measure and report our emissions, install new emission controls on our facilities, acquire allowances to authorize our GHG emissions, pay any taxes related to our GHG emissions and administer and manage a GHG emissions program. We may be unable to include some or all of such increased costs in the rates charged by our pipelines or other facilities, and any such recovery may depend on events beyond our control, including the outcome of future rate proceedings before the FERC or state regulatory agencies and the provisions of any final legislation or implementing regulations. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby adversely affect demand for the crude oil and natural gas that we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations. It is not possible at this time to predict with any accuracy the structure or outcome of any future legislative or regulatory efforts to address such emissions or the eventual costs to us of compliance.

Furthermore, there have been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. In addition, claims have been made against certain energy companies alleging that GHG emissions from crude oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages, or other liabilities. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely impact our business, financial condition and results of operations.

Moreover, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially hotter or colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

Safety and Security Regulations

Our crude oil and $CO_2$ pipelines are subject to construction, installation, operation and safety regulation by the U.S. Department of Transportation, or DOT, and various other federal, state and local agencies. Congress has enacted several pipeline safety acts over the years. Currently, the Pipeline and Hazardous Materials Safety Administration, or PHMSA, under DOT administers pipeline safety requirements for natural gas and hazardous liquid pipelines pursuant to detailed regulations set forth in 49 C.F.R. Parts 190 to 199. These regulations, among other things, address pipeline integrity management and pipeline operator qualification rules. In June 2016, Congress approved new pipeline safety legislation, the “Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016,” or the PIPES Act, which provides the PHMSA with additional authority to address imminent hazards by imposing emergency restrictions, prohibitions, and safety measures on owners and operators of gas or hazardous liquids pipeline facilities. Significant expenses could be incurred in the future if additional safety measures are required or if safety standards are raised and exceed the current pipeline control system capabilities.

We are subject to the PHMSA Integrity Management, or IM, regulations, which require that we perform baseline assessments of all pipelines that could affect a High Consequence Area, or HCA, including certain populated areas and environmentally sensitive areas. After completing a baseline assessment, we continue to assess all pipelines at specified intervals and periodically evaluate the integrity of each pipeline segment that could affect a HCA. The integrity of these pipelines must be assessed by internal inspection, pressure test, or equivalent alternative new technology.

The IM regulations required us to prepare an Integrity Management Plan, or IMP, that details the risk assessment factors, the overall risk rating for each segment of pipe, a schedule for completing the integrity assessment, the methods to assess pipeline integrity, and an explanation of the assessment methods selected. The regulations also require periodic review of HCA pipeline segments to ensure that adequate preventative and mitigative measures exist and that companies take prompt action to address pipeline integrity issues. No assurance can be given that the cost of testing and the required rehabilitation identified will not be material costs to us that may not be fully recoverable by tariff increases.

Recently, the PHMSA has proposed additional regulations for gas pipeline safety. For example, in March 2016, the PHMSA proposed a rule that would expand IM requirements beyond HCAs to gas pipelines in newly defined Moderate Consequence Areas. The public comment period closed in July 2016. Also, in January 2017, the PHMSA released an advance copy of its final rules to expand safety regulations for hazardous liquid pipelines by, among other things, expanding the required use of leak detection systems, requiring more frequent testing for corrosion and other flaws, and requiring companies to inspect pipelines in areas affected by extreme weather or natural disasters. The final rule was withdrawn by the PHMSA in January 2017, and it is unclear whether and to what extent the PHMSA will

move forward with its regulatory reforms.
We have developed a Risk Management Plan required by the EPA as part of our IMP. This plan is intended to minimize the offsite consequences of catastrophic spills. As part of this program, we have developed a mapping program. This mapping program identified HCAs and unusually sensitive areas along the pipeline right-of-ways in addition to mapping of shorelines to characterize the potential impact of a spill of crude oil on waterways.
Our crude oil, refined products and sodium minerals and sulfur services operations are also subject to the requirements of OSHA and comparable state statutes. Various other federal and state regulations require that we train all operations employees in Hazardous Communication ("HAZCOM") and disclose information about the hazardous materials used in our operations. Certain information must be reported to employees, government agencies and local citizens upon request.

Table of Contents

In most cases, states are responsible for enforcing the federal regulations and more stringent state pipeline regulations and inspection with respect to intrastate hazardous liquids pipelines, including crude oil, natural gas and $CO_2$ pipelines. In practice, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate any significant problems in complying with applicable state laws and regulations in those states in which we operate.

Our trucking operations are licensed to perform both intrastate and interstate motor carrier services. As a motor carrier, we are subject to certain safety regulations issued by the DOT. The trucking regulations cover, among other things, driver operations, log book maintenance, truck manifest preparations, safety placard placement on the trucks and trailer vehicles, drug and alcohol testing, operation and equipment safety and many other aspects of truck operations. We are also subject to OSHA with respect to our trucking operations.

The USCG regulates occupational health standards related to our marine operations. Shore-side operations are subject to the regulations of OSHA and comparable state statutes. The Maritime Transportation Security Act requires, among other things, submission to and approval of the USCG of vessel security plans.

Since the terrorist attacks of September 11, 2001, the U.S. Government has issued numerous warnings that energy assets could be the subject of future terrorist attacks. We have instituted security measures and procedures in conformity with federal guidance. We will institute, as appropriate, additional security measures or procedures indicated by the federal government. None of these measures or procedures should be construed as a guarantee that our assets are protected in the event of a terrorist attack.

Reporting of Ore Reserve and Mineral Resources

As of December 31, 2018, we had estimated mineral ore reserves in our Alkali Business. Our Alkali Business extracts trona, a natural hydrous sodium carbonate mineral used in the production of soda ash in southwestern Wyoming, USA. Soda ash, the commercial term for sodium carbonate ($Na_2CO_3$), is a basic ingredient in many consumer goods and a raw material used in a diversity of manufacturing processes.

U.S. registrants are required to report ore reserves under SEC Industry Guide 7, “Description of Property by Issuers Engaged or To Be Engaged in Significant Mining Operations.” Industry Guide 7 requires that sufficient technical and economic studies have been completed to reasonably assure economic extraction of the declared reserves, based on the parameters and assumptions current to the end of the reporting period.

We base our mineral reserve estimates on detailed geological, geotechnical, mine engineering and mineral processing inputs, and financial models developed and reviewed by employees/management of our Alkali Business, who possess years of experience directly related to the resources, mining and processing characteristics or financial performance of our operations. Additionally, our management and technical staff includes senior personnel who have remained closely involved with each of our active mining and mineral processing operations.

In preparing our reserve estimates for our Alkali operations at Green River Wyoming, we follow accepted mining industry practice and are guided by our long-term experience in extraction of trona ore from underground mining and sodium carbonate from solution mining in the district. Estimates of recoverable reserves for both techniques are routinely reconciled with actual production, and our Alkali ore reserves disclosures comply with SEC Industry Guide 7.

Under SEC Industry Guide 7, Proven reserves are the highest category of ore reserve estimates, whereby the quantity and quality have been computed from detailed sampling and modeling, while Probable reserves provide slightly lower geologic assurance.

Mineral Tenure - Wyoming

SEC Industry Guide 7 requires us to describe our rights to access and mine the minerals we report as ore reserves and to disclose any change in mineral tenure of material significance.  Our trona mining operations in Wyoming USA are secured through private and federal government leases, regulated by the BLM and WDEQ. All of our exploration and mining operations are subject to multiple levels of environmental regulatory review, that include approvals of environmental programs and public comment periods as pre-conditions to granting of mineral tenure. General descriptions of the rights and regulatory framework for minerals of relevance to Alkali follow here.

Ownership of land and minerals relative to trona beds in the Green River Basin of southwestern Wyoming is divided between the Federal Government (56%), Anadarko Petroleum (38%) and the State of Wyoming (6%). Anadarko's acquisition in 2000 of the Union Pacific Resources Group ("UPRG") included the land and mineral ownership originally granted to UPRG's parent company, the Union Pacific Railroad.

Leasing of Federal minerals under 41 Stat. 437, 30 U.S. Code § 124 (Section 23), "Agricultural entry or purchase of lands withdrawn or classified as containing sodium or sulphur," is authorized by the Mineral Leasing Act of February 25, 1920, and subsequent amendments. The U.S. Government's interests are administered by the BLM which has designated an

Table of Contents

area of 700,000 acres (283,280 hectares) as the Known Sodium Leasing Area ("KSLA"). In 1993, the BLM established a Mechanical Mining Trona Area ("MMTA") within the KSLA and suspended oil and gas leasing within the boundary. Our mineral tenure and assets at Green River are strengthened by the KSLA and MMTA.

Mineral leasing authority by the State of Wyoming is granted in W.S. 36-6-101(b). The primary environmental regulatory authority with respect to trona extraction is the WDEQ. The WDEQ is the primary issuer of the environmental permits relevant to our operations, including air quality permits, mining and reclamation permits, as well as class III and class V underground injection control permits.

Alkali Business - Green River, Wyoming

In 2017 we acquired our Alkali Business, making us the one of the world's leading producers of natural soda ash. Natural soda ash is refined from trona, a sodium carbonate mineral composed of soda ash ($Na_2CO_3$), sodium bicarbonate ($NaHCO_3$) and water with the chemical formula $Na_2CO_3NaHCO_32H_2O$. Approximately 60% of the world's natural soda ash is produced from trona extracted from underground mines and solution mining in the Green River Basin of southwestern Wyoming.

The Green River trona beds are collectively the largest deposit of trona and the undisputed largest source of raw material feed for the production of natural soda ash in the world. The origin of the trona deposits is the result of very unusual, geological circumstances.  Sodium-rich springs are believed to have fed ancient Lake Gosiute, a large, shallow inland lake that reached a maximum extent of over 15,000 square miles (about 40,000 sq km) around 50 million years ago. In response to repetitive cycles of lake expansion, contraction and evaporation, and changes in temperature and salinity, trona was precipitated in beds of remarkable purity and extent. In addition to trona, the evaporite sodium mineral assemblage includes variable levels of other sodium carbonate minerals as well as halite (NaCl). At least 25 beds of natural trona in the Wilkins Peak Member of the Eocene Green River Formation exceed at least locally three feet (1 m) in thickness and are estimated by the USGS to contain a cumulative resource of over 100 billion tons of trona. Individual trona beds are numbered in ascending order and trona beds of significance lie at modern depths between about 400 to 2,000 feet (120-600 m). Our current dry mining and solution mining operations exploit three trona beds, and our reserves are contained in four beds.

Our trona resources and mining operations are held under leases covering 88,342 acres (equivalent to 138 sq miles or 357 sq kilometers) over portions of 23 townships, primarily in two contiguous units informally known as the "Westvaco" and "Granger" blocks.  Mineral and mining rights are secured by leases from the Federal government, the State of Wyoming, and Anadarko Petroleum. We lease approximately 25,215 acres from the U.S. Government under the Mineral Leasing Act of 1920 (Title 30 §181) which includes trona under its definition of a "solid leasable mineral." Federal minerals are administered by the U.S. Bureau of Land Management (BLM). We lease 40,883 acres from Anadarko Land Corporation, a subsidiary of Anadarko Petroleum. Anadarko's acquisition of the Union Pacific Railroad Group in 2000 included alternate sections of land for 20 miles on either side of the trans-continental railroad, originally granted to Union Pacific under the Pacific Railroad Act of 1862 and subsequent railroad land grants. We also lease 22,243 acres from the State of Wyoming. Royalty payments range from 6% to 8% of the sales value of soda ash products.

Our Westvaco site is located approximately 25 miles (40-65 km) north-northwest of Green River. We extract trona ore from our Westvaco underground mine by mechanized, continuous mining methods. Our current underground dry mine production is from a single, near-horizontal bed approximately 10 feet (3.05 meters) thick at a depth from surface of 1500-1600 feet (450-490 meters). Ore is extracted from an extensive network of parallel drifts and connecting cross-cuts, known as room-and-pillar mining, and from longwall mining. Longwall miners shear off successive panels of ore which drops onto a conveyor belt for delivery to vertical shafts to be hoisted to the surface. The Westvaco mine has been in uninterrupted, continuous operation since its start in 1947 by Westvaco Chemical Company. The Westvaco interests were acquired by FMC in 1948.

We also extract trona by secondary recovery solution mining operations in previously dry mined portions of the Westvaco mine and in trona beds impacted by former dry mining of the Granger mine. The Granger mine and processing facility, about 10 miles (15 km) northeast of the eponymous town, operated as an underground mine from 1976 to 2002. FMC acquired the properties in 1999 by acquiring Tg Soda Ash, originally developed as a unit of Texasgulf and then owned by Elf Atochem. FMC converted the mine and mill to solution mining in 2005. In our secondary recovery solution mining operations, we pump process waters from our surface facilities, along with insoluble remnant from the processing of dry mined ore, into former underground mine workings where the insoluble constituents settle out and sodium carbonate and bicarbonate are leached from trona left behind from previous dry mining. The return mine water is pumped back to the Westvaco and Granger surface processing facilities for recovery of sodium solids.

Table of Contents

The following table summarizes the estimated in-place trona ore reserve of our Alkali Business:

| Mine Deposit | Reserve Category | Million c tons (dry weight) | Grade (% Trona) |
|---|---|---|---|
| Dry extraction | Proven | 298.3 | 89.7 |
| | Probable | 158.4 | 89.1 |
| Dry-mining | Total Reserves | 456.7 | 89.5 |
| Solution mining | Proven | — | — |
| | Probable | 446.0 | 86.3 |
| Solution mining | Total Reserves | 446.0 | 86.3 |
| Alkali | Total Reserves | 902.7 | 87.9 |

Our trona ore reserves are calculated from in-place trona-bearing material that can be economically and legally extracted and processed into commercial products at the time of reserve determination. Our reserves estimates are developed using industry-standard procedures and have been reviewed internally and externally to ensure compliance with SEC Industry Guide 7. Dry mining reserves and solution mining reserves are fundamentally different in terms of extraction methods and costs, predicted recoveries and the procedures used for reserve calculations.

We use "measured and indicated" resources as the primary basis in determining our proven and probably reserves. We define proven reserves and probable reserves as follows:

- Proven dry-mining reserves are measured reserves that fall within a 0.5 mile radius from drillhole data points previously mined areas with a 7.0 ft minimum ore thickness.
- Probable dry-mining reserves are indicated reserves that fall between 0.5 miles and 1.0 miles from drillhole data points or previously mined areas with a 7.0 ft minimum ore thickness.
- All solution mining reserves are designated as probable based on the degree of confidence in the reserve estimate related to uncertainties involving solution flow paths, trona ore surface area available for dissolution, and the inaccuracy of depletion verification methods. They consist of both measured resources falling with a 0.5 mile radius from drillhole data points or previously mined areas and indicated resources that fall between 0.5 miles and 1.0 miles from drillhole data points or previously mined areas. Solution mining reserves are not limited to a minimum ore thickness, but rather are subjected to a 50 foot halo limit into large blocks of trona adjacent to areas impacted by previous dry mining and adjacent to areas planned for future dry mining.

Estimated dry mining ore reserves of 456.7 million short tons include dilution from un-mineralized material within and marginal to the trona ore bed. We exclude support pillars from dry mining reserves, but a portion of the trona contained in the pillars is recovered by solution mining, as described below. We apply a bulk density factor of 133 lb/cu ft (2.16 g/cc) for conversion of volumes to mass. Key dry mining parameters include minimum trona ore bed thickness and minimum trona grade.

Our solution mining ore reserves of 446.0 million short tons are reported on an in-place basis, inclusive of dilution from insoluble material that remains in the ground. The solution mining reserves are calculated using recovery parameters developed from our 20+ years of cumulative secondary recovery solution mining experience. Key factors include the surface area of remaining support pillars and other trona-mineralized surfaces exposed to liquid solutions injected into voids created by dry mining, solubility and alkalinity data, and predicted dissolution rates.

Our dry mining reserves have a minimum trona grade of 77.4% and our solution mining reserves have a minimum trona grade of 69.8%. The balance of the ore consists of clays, shales, and other impurities.

Dry mined and solution mined trona are refined into soda ash at our Westvaco and Granger facilities, located within the boundaries of their respective contiguous lease blocks, and involve multiple processing lines, steam generation facilities, evaporation ponds, spare parts warehouses, maintenance shops, and offices for engineering, production, and support staff. Our Green River trona mining and processing facilities typically operate at an effective capacity of about four million short tons of marketable soda ash per year.

Table of Contents

The sum of our total proven and probable reserves estimated as of December 31, 2018, was 902.7 million short tons of trona ore equating to more than 500 million short tons of soda ash, sufficient to sustain production for over 100 years at our current production rates.
The economic viability of our reserves is based on our production costs, pricing, and cash flows for 2014-2018. We also apply certain additional assumptions when assessing whether the reserves meet the proven and probably standards and in determining the remaining life of our reserves, including, among other things, that:

- Annual production capacity remains approximately 4.0 million tons of soda ash per year.
- The average ore to ash ratio for the stated trona reserves is approximately 1.65:1.
- Sustaining capital is comparable over time to recent actual costs and short term projections.
- Mining and processing costs including consumption rates for energy and other consumables and the cost of those consumables are substantially comparable to 2014-2018 actual results.
- Mine and plant overhead and administration costs remain similar to recent actual performance.
- Average selling prices remain the same as the 2014-2018 average as estimated in the January 2019 USGS Mineral Commodity Summary, at approximately $138 per short ton of soda ash, f.o.b. plant site.
- Bed 15, which lies approximately 35 to 55 feet below bed 17, can be effectively dry mined after the completion of dry mining the overlying areas of Bed 17.
- All leases remain valid throughout the time required to mine the reserves.
- All permits remain valid throughout the life of the operation, and no new laws are enacted that require any extraordinary compliance which would significantly impact production or cost.
- New permits and approved mine plans will be obtained for mining the reserves that lie within existing leases, but outside of our current mining permit areas.
- Tailings storage capacity will be developed as necessary over the life of the mine and processing plants.
- Our 2017 reserve disclosure is partially based on the report of a third-party consultant that generated an updated reserve estimate as of September 1, 2017. Our reported reserves reflect that estimate, reconciled with 2017 and 2018 depletion.

Our mine plan is inherently forward-looking, under the meaning of the U.S. Securities Act of 1933 and subsequent amendments and is subject to uncertainties and unanticipated events beyond our control.

## Available Information

We make available free of charge on our internet website (www.genesisenergy.com) our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file the material with, or furnish it to, the SEC. These documents are also available at the SEC’s website (www.sec.gov). Additionally, on our internet website we make available our Corporate Governance Guidelines, Code of Business Conduct and Ethics, Audit Committee Charter and Governance, Compensation and Business Development Committee Charter. Information on our website is not incorporated into this Form 10-K or our other securities filings and is not a part of this Form 10-K or our other securities filings.

## Item 1A. Risk Factors

### Risks Related to Our Business

Our indebtedness could adversely restrict our ability to operate, affect our financial condition, and prevent us from complying with our requirements under our debt instruments and could prevent us from paying cash distributions to our unitholders.

We have outstanding debt and the ability to incur more debt. As of December 31, 2018, we had approximately $1.0 billion outstanding of senior secured indebtedness and an additional $2.5 billion of senior unsecured indebtedness. We must comply with various affirmative and negative covenants contained in our credit agreement and the indentures governing our notes, some of which may restrict the way in which we would like to conduct our business. Among other things, these covenants limit or will limit our ability to:

- incur additional indebtedness or liens;

Table of Contents

- make payments in respect of or redeem or acquire any debt or equity issued by us;
- sell assets;
- make loans or investments;
- make guarantees;
- enter into any hedging agreement for speculative purposes;
- acquire or be acquired by other companies; and
- amend some of our contracts.

The restrictions under our indebtedness may prevent us from engaging in certain transactions which might otherwise be considered beneficial to us and could have other important consequences to unitholders. For example, they could:

- increase our vulnerability to general adverse economic and industry conditions;
- limit our ability to make distributions; to fund future working capital, capital expenditures and other general partnership requirements; to engage in future acquisitions, construction or development activities; access capital markets (debt and equity); or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flows from operations to payments on our indebtedness or to comply with any restrictive terms of our indebtedness;
- limit our flexibility in planning for, or reacting to, changes in our businesses and the industries in which we operate; and
- place us at a competitive disadvantage as compared to our competitors that have less debt.

We may incur additional indebtedness (public or private) in the future under our existing credit agreement, by issuing debt instruments, under new credit agreements, under joint venture credit agreements, under capital leases or synthetic leases, on a project-finance or other basis or a combination of any of these. If we incur additional indebtedness in the future, it likely would be under our existing credit agreement or under arrangements that may have terms and conditions at least as restrictive as those contained in our existing credit agreement and the indentures governing our existing notes. Failure to comply with the terms and conditions of any existing or future indebtedness would constitute an event of default. If an event of default occurs, the lenders or noteholders will have the right to accelerate the maturity of such indebtedness and foreclose upon the collateral, if any, securing that indebtedness. In addition, if there is a change of control as described in our credit facility, that would be an event of default, unless our creditors agreed otherwise, and, under our credit facility, any such event could limit our ability to fulfill our obligations under our debt instruments and to make cash distributions to unitholders which could adversely affect the market price of our securities.

In addition, from time to time, some of our joint ventures may have substantial indebtedness, which will include affirmative and negative covenants and other provisions that limit their freedom to conduct certain operations, events of default, prepayment and other customary terms.

We may not be able to access adequate capital (debt and/or equity) on economically viable terms or any terms.

The capital markets (debt and equity) have previously been from time to time disrupted and volatile as a result of adverse conditions, including recessionary pressures, bubble-affects and precipitous commodity price declines. These circumstances and events, which can last for extended periods of time, have led to reduced capital availability, tighter lending standards and higher interest rates on loans for companies in the energy industry, especially non-investment grade companies. Although we cannot predict the future condition of the capital markets, future turmoil in capital markets and the related higher cost of capital could have a material adverse effect on our business, liquidity, financial condition and cash flows, particularly if our ability to borrow money from lenders or access the capital markets to finance our operations were to be impaired for long.

If we are unable to access the amounts and types of capital we seek at a cost and/or on terms that have been available to us historically, we could be materially and adversely affected. Such an inability to access capital could limit or prohibit our ability to execute significant portions of our business plan, such as executing our growth strategy, refinancing our debt and/or optimizing our capital structure.

We may not be able to fully execute our growth strategy due to various factors, such as unreceptive capital markets and/or excessive competition for acquisitions.

Our strategy contemplates substantial growth through the development and acquisition of a wide range of midstream and other energy infrastructure assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance our ability to compete effectively, diversify our asset portfolio and, thereby, provide more stable cash flow. We regularly consider and enter into discussions regarding, and are currently contemplating, additional potential joint ventures, stand-alone projects and other transactions that we believe will present opportunities to realize synergies, expand our role in the energy infrastructure business, and increase our market position and,

Table of Contents

ultimately, increase distributions to unitholders. A number of factors could adversely affect our ability to execute our growth strategy, including an inability to raise adequate capital on acceptable terms, competition from competitors and/or an inability to successfully integrate one or more acquired businesses into our operations.

We will need new capital to finance the future development and acquisition of assets and businesses. Limitations on our access to capital will impair our ability to execute this strategy. Expensive capital will limit our ability to develop or acquire accretive assets. Although we intend to continue to expand our business, this strategy may require substantial capital, and we may not be able to raise the necessary funds on satisfactory terms, if at all.

In addition, we experience competition for the assets we purchase or contemplate purchasing. Increased competition for a limited pool of assets could result in our not being the successful bidder more often or our acquiring assets at a higher relative price than that which we have paid historically. Either occurrence would limit our ability to fully execute our growth strategy. Our ability to execute our growth strategy may impact the market price of our securities.

We may be unable to integrate successfully businesses we acquire. We may incur substantial expenses, delays or other problems in connection with our growth strategy that could negatively impact our results of operations. Moreover, acquisitions and business expansions involve numerous risks, including:

- difficulties in the assimilation of the operations, technologies, services and products of the acquired companies or business segments;
- inefficiencies and complexities that can arise because of unfamiliarity with new assets and the businesses associated with them, including unfamiliarity with their markets; and
- diversion of the attention of management and other personnel from day-to-day business to the development or acquisition of new businesses and other business opportunities.

Our actual construction, development and acquisition costs could exceed our forecast, and our cash flow from construction and development projects may not be immediate.

Our forecast contemplates significant expenditures for the development, construction or other acquisition of infrastructure assets, including some construction and development projects with technological challenges. We (or our joint ventures) may not be able to complete our projects at the costs currently estimated. If we (or our joint ventures) experience material cost overruns, we will have to finance these overruns using one or more of the following methods:

- using cash from operations;
- delaying other planned projects;
- incurring additional indebtedness; or
- issuing additional debt or equity.

Any or all of these methods may not be available when needed or may adversely affect our future results of operations.

In addition, some construction projects require substantial investments over a long period of time before they begin generating any meaningful cash flow.

Fluctuations in interest rates could adversely affect our business.

We have exposure to movements in interest rates. The interest rates on our credit facility ($1.0 billion outstanding at December 31, 2018) are variable. Our results of operations and our cash flow, as well as our access to future capital and our ability to fund our growth strategy, could be adversely affected by significant increases in interest rates.

An increase in interest rates may also cause a corresponding decline in demand for equity investments, in general, and in particular, for yield-based equity investments such as our common units. Any such reduction in demand for our common units resulting from other more attractive investment opportunities may cause the trading price of our common units to decline.

We may not have sufficient cash from operations to pay the current level of quarterly distribution following the establishment of cash reserves and payment of fees and expenses.

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

- the volumes and prices at which we purchase and sell crude oil, natural gas, refined products, and caustic soda;
- the volumes of sodium hydrosulfide, or NaHS, and soda ash that we receive for our sodium minerals and sulfur services and the prices at which we sell NaHS and soda ash;

- the demand for our services;
- the level of competition;

Table of Contents

- the level of our operating costs;
- the effect of worldwide energy conservation measures;
- governmental regulations and taxes;
- the level of our general and administrative costs; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors that include:

- the level of capital expenditures we make, including the cost of acquisitions (if any);
- our debt service requirements;
- fluctuations in our working capital;
- restrictions on distributions contained in our debt instruments;
- our ability to borrow under our working capital facility to pay distributions; and
- the amount of cash reserves required in the conduct of our business.

Our ability to pay distributions each quarter depends primarily on our cash flow, including cash flow from financial reserves and working capital borrowings, and our cash requirements, so it is not solely a function of profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and we may not make distributions during periods when we record net income.

Our profitability and cash flow are dependent on our ability to increase or, at a minimum, maintain our current commodity-crude oil, natural gas, refined products, soda ash, NaHS and caustic soda-volumes, which often depend on actions and commitments by parties beyond our control.

Our profitability and cash flow are dependent on our ability to increase or, at a minimum, maintain our current commodity-crude oil, natural gas, refined products, soda ash, NaHS, and caustic soda-volumes. We access commodity volumes through various sources, such as our mines, producers, service providers (including gatherers, shippers, marketers and other aggregators) and refiners. Depending on the needs of each customer and the market in which it operates, we can either provide a service for a fee (as in the case of our pipeline, marine vessel and railcar transportation operations), we can acquire the commodity from our customer and resell it to another party, or, in the case of soda ash, we can produce the commodity ourselves.

Our source of volumes depends on successful exploration and development of additional crude oil and natural gas reserves by others; our successful development of our trona reserves, continued demand for refining and our related sulfur removal and other services, for which we are paid in NaHS; the breadth and depth of our logistics operations; the extent that third parties provide NaHS for resale; and other matters beyond our control.

The crude oil, natural gas and refined products available to us and our refinery customers are derived from reserves produced from existing wells, and these reserves naturally decline over time. In order to offset this natural decline, our energy infrastructure assets must access additional reserves. Additionally, some of the projects we have planned or recently completed are dependent on reserves that we expect to be produced from newly discovered properties that producers are currently developing.

Finding and developing new reserves is very expensive, requiring large capital expenditures by producers for exploration and development drilling, installing production facilities and constructing pipeline extensions to reach new wells. Many economic and business factors out of our control can adversely affect the decision by any producer to explore for and develop new reserves. These factors include the prevailing market price of the commodity, the capital budgets of producers, the depletion rate of existing reservoirs, the success of new wells drilled, environmental concerns, regulatory initiatives, cost and availability of equipment, capital budget limitations or the lack of available capital and other matters beyond our control. Additional reserves, if discovered, may not be developed in the near future or at all. The precipitous decline in crude oil and natural gas prices beginning in late 2014, which continued into 2018 has forced most producers to significantly curtail their planned capital expenditures. Thus, crude oil and natural gas production in our market areas could decline, which could have a material negative impact on our revenues and prospects.

Demand for our services is dependent on the demand for crude oil and natural gas. Any decrease in demand for crude oil or natural gas, including by those refineries or connecting carriers to which we deliver could adversely affect our cash flows. The demand for crude oil also is dependent on the competition from refineries, the impact of future economic conditions, fuel conservation measures, alternative fuel requirements or sources fuel sources such as electricity, coal, fuel oils or nuclear energy, government regulation or technological advances in fuel economy and energy generation devices, all of which could reduce demand for our services. A reduction in demand for our services in the markets we serve could result in impairments of our assets and have a material adverse effect on our business, financial condition and results of operations.

Table of Contents

Our ability to access NaHS depends primarily on the demand for our proprietary sulfur removal process. Demand for our services could be adversely affected by many factors, including lower refinery utilization rates, U.S. refineries accessing more “sweet” (instead of "sour") crude, and the development of alternative sulfur removal processes that might be more economically beneficial to refiners.

We are dependent on third parties for NaOH for use in our sulfur removal process as well as volume to market to third parties. Should regulatory requirements or operational difficulties disrupt the manufacture of caustic soda by these producers, we could be affected.

Our sulfur removal operations are dependent upon the supply of caustic soda, the demand for NaHS, and the continuing operations of the refiners for whom we process sour natural gas.

Caustic soda is a major component of the proprietary sulfur removal process we provide to our refinery customers. Because we are a large consumer of caustic soda, we can leverage our economies of scale and logistics capabilities to effectively market caustic soda to third parties. NaHS, the resulting by-product from our sulfur removal operations, is a vital ingredient in a number of industrial and consumer products and processes. Any decrease in the supply of caustic soda could affect our ability to provide sulfur removal services to refiners and any decrease in the demand for NaHS by the parties to whom we sell the NaHS could adversely affect our business. Refineries’ need for our sulfur removal services is also dependent on refining competition from other refineries by refiners to process more “sweet” (instead of sour) crude, the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, government regulation or technological advances in fuel economy and energy generation devices, all of which could reduce demand for our services.

Our crude oil and natural gas transportation operations are dependent upon demand for crude oil by refiners, primarily in the Midwest and Gulf Coast, and the demand for natural gas.

Any decrease in this demand for crude oil by those refineries or connecting carriers to which, or for the natural gas, we deliver could adversely affect our cash flows. Those refineries’ demand for crude oil also is dependent on the competition from other refineries, the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, government regulation or technological advances in fuel economy and energy generation devices, all of which could reduce demand for our services. The demand for natural gas is dependent on the impact of future economic conditions, fuel conservation measures, alternative fuel requirements and alternative fuel sources such as electricity, coal, fuel oils or nuclear energy, government regulation or technological advances in fuel economy and energy generation devices, all of which could reduce demand for our services.

We face intense competition to obtain crude oil, natural gas and refined products volumes.

Our competitors-gatherers, transporters, marketers, brokers and other aggregators-include integrated, large and small independent energy companies, as well as their marketing affiliates, who vary widely in size, financial resources and experience. Some of these competitors have capital resources many times greater than ours and control substantially greater supplies of crude oil, natural gas and refined products.

Even if reserves exist or refined products are produced in the areas accessed by our facilities, we may not be chosen by the refiners or producers to gather, refine, market, transport, store or otherwise handle any of these crude oil and natural gas reserves, NaHS, caustic soda, soda ash or other refined products. We compete with others for any such volumes on the basis of many factors, including:

- geographic proximity to the production and/or refineries;
- costs of connection;
- available capacity;
- rates;
- logistical efficiency in all of our operations;
- operational efficiency in our sulfur removal business;
- customer relationships; and
- access to markets.

Additionally, on our onshore pipelines most of our third-party shippers do not have long-term contractual commitments to ship crude oil on our pipelines. A decision by a shipper to substantially reduce or cease to ship volumes of crude oil on our pipelines could cause a significant decline in our revenues. In Mississippi, we are dependent on interconnections with other pipelines to provide shippers with a market for their crude oil, and in Texas, we are dependent on interconnections with other pipelines to provide shippers with transportation to our pipeline. Any reduction of throughput available to our shippers on these interconnecting pipelines as a result of testing, pipeline repair, reduced operating pressures or other causes could result in reduced throughput on our pipelines that would adversely affect our cash flows and results of operations.

Fluctuations in demand for crude oil or natural gas or availability of refined products or NaHS, such as those caused by refinery downtime or shutdowns, can negatively affect our operating results. Reduced demand in areas we service with our pipelines, marine vessels, rail facilities and trucks can result in less demand for our transportation services. Many of our crude oil and natural gas transportation customers are producers whose drilling activity levels and spending for transportation have been, and may continue to be, impacted by the deterioration in the commodity markets.

Many of our customers finance their drilling activities through cash flow from operations, the incurrence of debt or the issuance of equity. New credit facilities and other debt financing from institutional sources have generally become more difficult and expensive to obtain, and there may be a general reduction in the amount of credit available in the markets in which we conduct business. Additionally, many of our customers' equity values have substantially declined. Adverse price changes put downward pressure on drilling budgets for crude oil and natural gas producers, which have resulted, and could continue to result, in lower volumes than we otherwise would have seen being transported on our pipeline and transportation systems, which could have a material negative impact on our revenues and prospects. For example, prices for crude oil declined precipitously in the second half of 2014 from approximately $109 per barrel in June 2014 to approximately $30 per barrel in January 2016, recovered to approximately $76 per barrel in October 2018, and dropped to approximately $45 per barrel as of the end of December 2018, and such volatility may continue going forward.

Fluctuations in prices for crude oil, refined petroleum products, NaHS, soda ash and caustic soda could adversely affect our business.

Because we purchase (or otherwise acquire) and sell crude oil, refined petroleum products, NaHS soda ash and caustic soda we are exposed to some direct commodity price risks. Prices for those commodities can fluctuate in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control, which could have an adverse effect on our cash flows, profit and/or Segment Margin. We attempt to limit those commodity price risks through back-to-back purchases and sales, hedges and other contractual arrangements; however, we cannot completely eliminate our commodity price risk exposure.

Our use of derivative financial instruments could result in financial losses.

We use derivative financial instruments and other hedging mechanisms from time to time to limit a portion of the effects resulting from changes in commodity prices. To the extent we hedge our commodity price exposure, we forego the benefits we would otherwise experience if commodity prices were to increase. In addition, we could experience losses resulting from our hedging and other derivative positions. Such losses could occur under various circumstances, including if our counterparty does not perform its obligations under the hedge arrangement, our hedge is imperfect, or our hedging policies and procedures are not followed.

Non-utilization of certain assets could significantly reduce our profitability due to the fixed costs incurred with respect to such assets.

From time to time in connection with our business, we may lease or otherwise secure the right to use certain third party assets (such as railcars, trucks, barges, pipeline capacity, storage capacity and other similar assets) with the expectation that the revenues we generate through the use of such assets will be greater than the fixed costs we incur pursuant to the applicable leases or other arrangements. However, when such assets are not utilized or are under-utilized, our profitability is negatively affected because the revenues we earn are either non-existent or reduced (in the event of under-utilization), but we remain obligated to continue paying any applicable fixed charges, in addition to incurring any other costs attributable to the non-utilization of such assets. For example, in connection with our rail operations, we lease all of our railcars that obligate us to pay the applicable lease rate without regard to utilization. If business conditions are such that we do not utilize a portion of our leased assets for any period of time, we will still be obligated to pay the applicable fixed lease rate. In addition, during the period of time that we are not utilizing such assets, we will incur incremental costs associated with the cost of storing such assets, and we will continue to incur costs for maintenance and upkeep. Our failure to utilize a significant portion of our leased assets and other similar assets could have a significant negative impact on our profitability and cash flows.

In addition, certain of our field and pipeline operating costs and expenses are fixed and do not vary with the volumes we gather and transport. These costs and expenses may not decrease ratably or at all should we experience a reduction in our volumes transported by truck, marine vessel or rail or transported by our pipelines. As a result, we may experience declines in our margin and profitability if our volumes decrease.

Table of Contents

We cannot cause our joint ventures to take or not to take certain actions unless some or all of the joint venture participants agree.

Due to the nature of joint ventures, each participant (including us) in our material joint ventures has made substantial investments (including contributions and other commitments) in that joint venture and, accordingly, has required that the relevant charter documents contain certain features designed to provide each participant with the opportunity to participate in the management of the joint venture and to protect its investment in that joint venture, as well as any other assets which may be substantially dependent on or otherwise affected by the activities of that joint venture. These participation and protective features include a corporate governance structure that consists of a management committee composed of members, only some of which are appointed by us. In addition, many of our joint ventures are operated by our "partners" and have "stand-alone" credit agreements that limit their freedom to take certain actions. Thus, without the concurrence of the other joint venture participants and/or the lenders of our joint venture participants, we cannot cause our joint ventures to take or not to take certain actions, even though those actions may be in the best interest of the joint ventures or us.

The insolvency of an operator of our joint ventures, the failure of an operator of our joint ventures to adequately perform operations or an operator's breach of applicable agreements could reduce our revenue and result in our liability to governmental authorities for compliance with environmental, safety and other regulatory requirements and to the operator's suppliers and vendors. As a result, the success and timing of development activities of our joint ventures operated by others and the economic results derived therefrom depends upon a number of factors outside our control, including the operator's timing and amount of capital expenditures, expertise and financial resources, and the inclusion of other participants.

In addition, joint venture participants may have obligations that are important to the success of the joint venture, such as the obligation to pay their share of capital and other costs of the joint venture. The performance and ability of third parties to satisfy their obligations under joint venture arrangements is outside our control. If these third parties do not satisfy their obligations under these arrangements, our business may be adversely affected.

We are exposed to the credit risk of our customers in the ordinary course of our business activities.

When we (or our joint ventures) market our products or services, we (or our joint ventures) must determine the amount, if any, of the line of credit. Since certain transactions can involve very large payments, the risk of nonpayment and nonperformance by customers, industry participants and others is an important consideration in our business.

For example, in those cases where we provide division order services for crude oil and natural gas purchased at the wellhead, we may be responsible for distribution of proceeds to all of the interest owners. In other cases, we pay all of or a portion of the production proceeds to an operator who distributes these proceeds to the various interest owners. These arrangements expose us to operator credit risk. As a result, we must determine that operators have sufficient financial resources to make such payments and distributions and to indemnify and defend us in case of a protest, action or complaint.

Additionally, we sell NaHS, soda ash and caustic soda to customers in a variety of industries. Some of these customers are in industries that have been impacted by a decline in demand for their products and services. Even if our credit review and analytical procedures work properly, we have experienced, and we could continue to experience losses in dealings with other parties.

Further, many of our customers were impacted by the weakened economic conditions, and precipitous decline in commodity prices, such as crude oil, natural gas, copper, molybdenum, and aluminum experienced in recent years in a manner that influenced the need for our products and services and their ability to pay us for those products and services. It is uncertain if commodity prices will increase in the near future.

We may not be able to renew our marine transportation time charters and contracts when they expire at favorable rates, for extended periods, or at all, which may increase our exposure to the spot market and lead to lower revenues and increased expenses.

During the year ended December 31, 2018, our marine transportation segment received approximately 62% of its revenue from time charters and other fixed contracts, which help to insulate us from revenue fluctuations caused by weather, navigational delays and short-term market declines. We earned approximately 38% of our marine transportation revenues from spot contracts, where competition is high and rates are typically volatile and subject to short-term market fluctuations, and where we bear the risk of vessel downtime due to weather and navigational delays. If we deploy a greater percentage of our vessels in the spot market, we may experience a lower overall utilization of our fleet through waiting time or ballast voyages, leading to a decline in our operating revenue and gross profit. There can be no assurance that we will be able to enter into future time charters or other fixed contracts on terms favorable to us. For further discussion of our marine transportation contracts, see “Marine Transportation - Customers”.

Table of Contents

Our operations are subject to federal, state and local environmental protection and safety laws and regulations.

Our operations are subject to the risk of incurring substantial environmental and safety related costs and liabilities. In particular, our operations are subject to stringent federal, state and local environmental protection and safety laws and regulations. These laws and regulations may (i) require the acquisition of and compliance with permits for regulated activities, (ii) limit or prohibit operations on environmentally sensitive lands such as wetlands or wilderness areas, seismically sensitive areas, or areas inhabited by endangered or threatened species, (iii) result in capital expenditures to limit or prevent emissions or discharges, and (iv) place burdensome restrictions on our operations, including the management and disposal of wastes. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, including the assessment of monetary penalties, the imposition of investigatory and remedial obligations, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and the issuance of orders enjoining future operations or imposing additional compliance requirements. Changes in environmental laws and regulations occur frequently, typically increasing in stringency through time, and any changes that result in more stringent and costly operating restrictions, emission control, waste handling, disposal, cleanup and other environmental requirements have the potential to have a material adverse effect on our operations. While we believe that we are in substantial compliance with current environmental laws and regulations and that continued compliance with existing requirements would not materially affect us, there is no assurance that this trend will continue in the future. Revised or new additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and cash flows. Moreover, our operations, including the transportation and storage of crude oil, natural gas and other commodities, involves a risk that crude oil, natural gas and related hydrocarbons or other substances may be released into the environment, which may result in substantial expenditures for a response action, significant government penalties, liability to government agencies for natural resources damages, liability to private parties for personal injury or property damages, and significant business interruption. These costs and liabilities could rise under increasingly strict environmental and safety laws, including regulations and enforcement policies, or claims for damages to property or persons resulting from our operations. If we are unable to recover such resulting costs through increased rates or insurance reimbursements, our cash flows and distributions to our unitholders could be materially affected. See “Regulation - Environmental Regulations” for additional discussion of environmental laws and regulations affecting our operations.

Climate change legislation and regulatory initiatives may decrease demand for the products we store, transport and sell and increase our operating costs.

In recent years, federal, state, and local governments have taken steps to reduce emissions of GHGs. The EPA has finalized a series of GHG monitoring, reporting, and emission control rules for the oil and natural gas industry, and the U.S. Congress has, from time to time, considered various proposals to reduce GHG emissions. Almost half of the states, either individually or through multi-state regional initiatives, have already taken legal measures to reduce GHG emissions, primarily through the planned development of GHG emission inventories and/or GHG cap-and-trade programs. While we are subject to certain federal GHG monitoring, reporting and emission control rules, our operations are not adversely and materially impacted by existing federal, state and local climate change initiatives. However, our compliance with any future legislation or regulation of GHGs, if it occurs, may result in materially increased compliance and operating costs.

Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S. beginning in 2011 for emissions occurring in 2010. Further, in November 2010, the EPA expanded its existing GHG reporting rule to include onshore and offshore crude oil and natural gas production and onshore processing, transmission, storage and distribution facilities, which may include certain of our facilities, beginning in 2012 for emissions occurring in 2011. In October 2015, the EPA amended the GHG reporting rule to add the reporting of GHG emissions from gathering and boosting systems, completions and workovers of crude oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines. As a result of this continued regulatory focus, future GHG regulations of the crude oil and natural gas industry remain a possibility.

Further, the U.S. Congress has from time to time considered various proposals to reduce GHG emissions, and almost half of the states, either individually or through multi-state regional initiatives, have already taken legal measures to reduce GHG emissions, primarily through the planned development of GHG emission inventories and/or GHG cap-and-trade programs. The net effect of this legislation is to impose increasing costs on the combustion of carbon-based fuels such as crude oil, refined petroleum products and natural gas. Our compliance with any future legislation or regulation of GHGs, if it occurs, may result in materially increased compliance and operating costs.

In addition, in December 2015, the United States participated in the 21st Conference of the Parties, or COP-21, of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake “ambitious efforts” to limit the average global temperature, and to conserve and enhance sinks and reservoirs of GHGs. The Agreement went into effect on November 4, 2016. The Agreement establishes a framework for the parties to

Table of Contents

cooperate and report actions to reduce GHG emissions. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement, and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. The Paris Agreement sets forth a specific exit process, whereby a party may not provide notice of its withdrawal until three years from the effective date, with such withdrawal taking effect one year from such notice. It is not clear what steps the Trump Administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

Efforts to regulate or restrict emissions of GHGs in areas that we conduct business could adversely affect the demand for the products that we transport, store and distribute and, depending on the particular program adopted, could increase our costs to operate and maintain our facilities by requiring that we, among other things, measure and report our emissions, install new emission controls on our facilities, acquire allowances to authorize our GHG emissions, pay any taxes related to our GHG emissions and administer and manage a GHG emissions program. We may be unable to include some or all of such increased costs in the rates charged by our pipelines or other facilities, and any such recovery may depend on events beyond our control, including the outcome of future rate proceedings before the FERC or state regulatory agencies and the provisions of any final legislation or implementing regulations. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby adversely affect demand for the crude oil and natural gas that we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations. It is not possible at this time to predict with any accuracy the structure or outcome of any future legislative or regulatory efforts to address such emissions or the eventual costs to us of compliance.

Furthermore, there have been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. In addition, claims have been made against certain energy companies alleging that GHG emissions from crude oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages, or other liabilities. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely impact our business, financial condition and results of operations.

Moreover, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially hotter or colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

Restrictions on drilling or mining activities to protect certain species of wildlife could adversely affect our business.

The federal Endangered Species Act and analogous state statutes restrict activities that may adversely affect endangered and threatened species or their habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act, though, in December 2017, the U.S. Fish and Wildlife Service provided guidance limiting the reach of the Act. The designation of previously unidentified endangered or threatened species in areas where we operate could cause us to incur additional costs or become subject to operating delays, restrictions or bans.

We have reclamation and mine closing obligations. If the assumptions underlying our accruals are inaccurate, we could be required to expend greater amounts than anticipated.

Our mining operations in Wyoming are subject to mine permits issued by the Land Quality Division of the Wyoming Department of Environmental Quality (“WDEQ”). WDEQ imposes detailed reclamation obligations on us as a holder of mine permits. We accrue for the costs of current mine disturbance and of final mine closure. The amounts recorded are dependent upon a number of variables, including the estimated future closure costs, estimated proven reserves, assumptions involving profit margins, inflation rates and the assumed credit-adjusted risk-free interest rates. If these accruals are insufficient or our liability in a particular year is greater than currently anticipated, our future operating results could be materially adversely affected.

Table of Contents

Failure to obtain or renew surety bonds on acceptable terms could affect our ability to secure reclamation obligations and, therefore, our ability to conduct our mining operations.

We are required to obtain surety bonds or post other financial security to secure performance or payment of certain long-term obligations, such as mine closure or reclamation costs. The amount of security required to be obtained can change as the result of new laws, as well as changes to the factors used to calculate the bonding or security amounts. We may have difficulty procuring or maintaining our surety bonds. Our bond issuers may demand higher fees or additional collateral, including letters of credit or other terms less favorable to us upon those renewals. Because we are required to have these bonds or other acceptable security in place before mining can commence or continue, our failure to maintain surety bonds, letters of credit or other guarantees or security arrangements would materially and adversely affect our ability to mine trona. That failure could result from a variety of factors, including lack of availability, higher expense or unfavorable market terms, the exercise by third-party surety bond issuers of their right to refuse to renew the surety and restrictions on availability of collateral for current and future third-party surety bond issuers under the terms of our financing arrangements.

Regulation of the rates, terms and conditions of services and a changing regulatory environment could affect our financial position, results of operations or cash flow.

FERC regulates certain of our energy infrastructure assets engaged in interstate operations. Our intrastate pipeline operations are regulated by state agencies. Our railcar operations are subject to the regulatory jurisdiction of the Federal Railroad Administration of the DOT, the Occupational Safety and Health Administration, as well as other federal and state regulatory agencies. This regulation extends to such matters as:

- rate structures;
- rates of return on equity;
- recovery of costs;
- the services that our regulated assets are permitted to perform;
- the acquisition, construction and disposition of assets; and
- to an extent, the level of competition in that regulated industry.

In addition, some of our pipelines and other infrastructure are subject to laws providing for open and/or non-discriminatory access.

Given the extent of this regulation, the evolving nature of federal and state regulation and the possibility for additional changes, the current regulatory regime may change and affect our financial position, results of operations or cash flow.

A natural disaster, accident, terrorist attack or other interruption event involving us could result in severe personal injury, property damage and/or environmental damage, which could curtail our operations and otherwise adversely affect our assets and cash flow.

Some of our operations involve significant risks of severe personal injury, property damage and environmental damage, any of which could curtail our operations and otherwise expose us to liability and adversely affect our cash flow. Virtually all of our operations are exposed to the elements, including hurricanes, tornadoes, storms, floods and earthquakes. A significant portion of our operations are located along the U.S. Gulf Coast, and our offshore pipelines are located in the Gulf of Mexico. These areas can be subject to hurricanes.

If one or more facilities that are owned by us or that connect to us is damaged or otherwise affected by severe weather or any other disaster, accident, catastrophe or event, our operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply our facilities or other stoppages arising from factors beyond our control. These interruptions might involve significant damage to people, property or the environment, and repairs might take from a week or less for a minor incident to six months or more for a major interruption. Any event that interrupts the fees generated by our energy infrastructure assets, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying our interest obligations as well as unitholder distributions and, accordingly, adversely impact the market price of our securities. Additionally, the proceeds of any property insurance maintained by us may not be paid in a timely manner or be in an amount sufficient to meet our needs if such an event were to occur, and we may not be able to renew it or obtain other desirable insurance on commercially reasonable terms, if at all.

On September 11, 2001, the U.S. was the target of terrorist attacks of unprecedented scale. Since the September 11 attacks, the U.S. government has issued warnings that energy assets, specifically the nation's pipeline infrastructure, may be the future targets of terrorist organizations. These developments have subjected our operations to increased risks. Any future terrorist attack at our facilities, those of our customers and, in some cases, those of other pipelines, could have a material adverse effect on our business.

Table of Contents

Our business could be negatively impacted by security threats, including cybersecurity threats, and related disruptions.
We rely on our information technology infrastructure to process, transmit and store electronic information, including information we use to safely operate our assets. While we believe that we maintain appropriate information security policies and protocols, we face cybersecurity and other security threats to our information technology infrastructure, which could include threats to our operational and safety systems that operate our pipelines, facilities and other assets. We could face unlawful attempts to gain access to our information technology infrastructure, including coordinated attacks from hackers, whether state-sponsored groups, “hacktivists,” or private individuals. The age, operating systems or condition of our current information technology infrastructure and software assets and our ability to maintain and upgrade such assets could affect our ability to resist cybersecurity threats.
Our information technology infrastructure is critical to the efficient operation of our business and essential to our ability to perform day-to-day operations. Breaches in our information technology infrastructure or physical facilities, or other disruptions, could result in damage to our assets, loss of intellectual property, impairment of our ability to conduct our operations, disruption of our customers’ operations, loss or damage to our customer data delivery systems, safety incidents, damage to the environment and could have a material adverse effect on our operations, financial position and results of operations. It is also possible that breaches to our systems could go unnoticed for some period of time.
Our business would be adversely affected if we failed to comply with the Jones Act foreign ownership provisions.
We are subject to the Jones Act and other federal laws that restrict maritime cargo transportation between points in the U.S. only to vessels operating under the U.S. flag, built in the U.S., at least 75% owned and operated by U.S. citizens (or owned and operated by other entities meeting U.S. citizenship requirements to own vessels operating in the U.S. coastwise trade and, in the case of limited partnerships, where the general partner meets U.S. citizenship requirements) and manned by U.S. crews. To maintain our privilege of operating vessels in the Jones Act trade, we must maintain U.S. citizen status for Jones Act purposes. To ensure compliance with the Jones Act, we must be U.S. citizens qualified to document vessels for coastwise trade. We could cease being a U.S. citizen if certain events were to occur, including if non-U.S. citizens were to own 25% or more of our equity interest or were otherwise deemed to control us or our general partner. We are responsible for monitoring ownership to ensure compliance with the Jones Act. The consequences of our failure to comply with the Jones Act provisions on coastwise trade, including failing to qualify as a U.S. citizen, would have an adverse effect on us as we may be prohibited from operating our vessels in the U.S. coastwise trade or, under certain circumstances, permanently lose U.S. coastwise trading rights or be subject to fines or forfeiture of our vessels.
Our business would be adversely affected if the Jones Act provisions on coastwise trade or international trade agreements were modified or repealed or as a result of modifications to existing legislation or regulations governing the crude oil and natural gas industry in response to the recent lifting of the crude oil export ban and the Deepwater Horizon drilling rig incident in the U.S. Gulf of Mexico and subsequent crude oil spill.
If the restrictions contained in the Jones Act were repealed or altered or certain international trade agreements were changed, the maritime transportation of cargo between U.S. ports could be opened to foreign flag or foreign-built vessels. The Secretary of the Department of Homeland Security, or the Secretary, is vested with the authority and discretion to waive the coastwise laws if the Secretary deems that such action is necessary in the interest of national defense. Any waiver of the coastwise laws, whether in response to natural disasters or otherwise, could result in increased competition from foreign product carrier and barge operators, which could reduce our revenues and cash available for distribution.
In December 2015, Congress voted to lift the four decade crude oil export ban. Although the impact of this legislation is not yet determinable, increased exports of U.S. crude oil may lead to increased calls to repeal or modify the Jones Act. Even before lifting the export ban, in the past several years, interest groups have lobbied Congress to repeal or modify the Jones Act to facilitate foreign-flag competition for trades and cargoes currently reserved for U.S. flag vessels under the Jones Act. Foreign-flag vessels generally have lower construction costs and generally operate at significantly lower costs than we do in U.S. markets, which would likely result in reduced charter rates. We believe that continued efforts will be made to modify or repeal the Jones Act. If these efforts are successful, foreign-flag vessels could be permitted to trade in the U.S. coastwise trade and significantly increase competition with our fleet,

which could have an adverse effect on our business.
Events within the crude oil and natural gas industry, such as the April 2010 fire and explosion on the Deepwater Horizon drilling rig in the U.S. Gulf of Mexico and the resulting crude oil spill and moratorium on certain drilling activities in the U.S. Gulf of Mexico implemented by the Bureau of Ocean Energy Management, Regulation and Enforcement (formerly, the Minerals Management Service), may adversely affect our customers' operations and, consequently, our operations. Such events may also subject companies operating in the crude oil and natural gas industry, including us, to additional regulatory scrutiny and result in additional regulations and restrictions adversely affecting the U.S. crude oil and natural gas industry.

A decrease in the cost of importing refined petroleum products could cause demand for U.S. flag product carrier and barge capacity and charter rates to decline, which would decrease our revenues and our ability to pay cash distributions on our units.

The demand for U.S. flag product carriers and barges is influenced by the cost of importing refined petroleum products. Historically, charter rates for vessels qualified to participate in the U.S. coastwise trade under the Jones Act have been higher than charter rates for foreign flag vessels. This is due to the higher construction and operating costs of U.S. flag vessels under the Jones Act requirements that such vessels be built in the U.S. and manned by U.S. crews. This has made it less expensive for certain areas of the U.S. that are underserved by pipelines or which lack local refining capacity, such as in the Northeast, to import refined petroleum products carried aboard foreign flag vessels than to obtain them from U.S. refineries. If the cost of importing refined petroleum products decreases to the extent that it becomes less expensive to import refined petroleum products to other regions of the East Coast and the West Coast than producing such products in the U.S. and transporting them on U.S. flag vessels, demand for our vessels and the charter rates for them could decrease.

The lifting of the U.S. crude oil export ban could adversely impact our U.S. Flag Fleet.

In December 2015, Congress voted to lift the four decade crude oil export ban. Although the impact of this legislation on our U.S. Flag fleet’s operations is not determinable, the easing of the crude oil export ban could result in reduced coastwise transportation of crude oil, which may have an adverse impact on our U.S. Flag segment.

We face periodic dry-docking costs for our vessels, which can be substantial.

Vessels must be dry-docked periodically for regulatory compliance and for maintenance and repair. Our dry-docking requirements are subject to associated risks, including delay, cost overruns, lack of necessary equipment, unforeseen engineering problems, employee strikes or other work stoppages, unanticipated cost increases, inability to obtain necessary certifications and approvals and shortages of materials or skilled labor. A significant delay in dry-dockings could have an adverse effect on our marine transportation contract commitments. The cost of repairs and renewals required at each dry-dock are difficult to predict with certainty and can be substantial.

The U.S. inland waterway infrastructure is aging and may result in increased costs and disruptions to our marine transportation segment.

Maintenance of the U.S. inland waterway system is vital to our marine transportation operations. The system is composed of over 12,000 miles of commercially navigable waterway, supported by over 240 locks and dams designed to provide flood control, maintain pool levels of water in certain areas of the country and facilitate navigation on the inland river system. The U.S. inland waterway infrastructure is aging, with more than half of the locks over 50 years old. As a result, due to the age of the locks, scheduled and unscheduled maintenance outages may be more frequent in nature, resulting in delays and additional operating expenses. Failure of the federal government to adequately fund infrastructure maintenance and improvements in the future would have a negative impact on our ability to deliver products for its marine transportation customers on a timely basis.

Risks Related to Our Partnership Structure

Our significant unitholders may sell units or other limited partner interests in the trading market, which could reduce the market price of common units.

As of December 31, 2018, we have a number of significant unitholders. For example, certain members of the Davison family (including their affiliates) and management owned approximately 17 million or 13.7% of our common units. From time to time, we also may have other unitholders that have large positions in our common units. In the future, any such parties may acquire additional interest or dispose of some or all of their interest. If they dispose of a substantial portion of their interest in the trading markets, such sales could reduce the market price of common units. In connection with certain transactions, we have put in place resale shelf registration statements, which allow unit holders thereunder to sell their common units at any time (subject to certain restrictions) and to include those securities in any equity offering we consummate for our own account.

Individual members of the Davison family can exert significant influence over us and may have conflicts of interest with us and may be permitted to favor their interests to the detriment of our other unitholders.

James E. Davison and James E. Davison, Jr., each of whom is a director of our general partner, each own a significant portion of our common units, including our Class B Common Units, the holders of which elect our directors. Other members of the Davison family also own a significant portion of our common units. Collectively, members of the Davison family and their affiliates own approximately 10.3% of our Class A Common Units and 77.0% of our Class B Common Units and are able to exert significant influence over us, including the ability to elect at least a majority of the members of our board of directors and the ability to control most matters requiring board approval, such as material business strategies, mergers, business combinations, acquisitions or dispositions of assets, issuances of additional partnership securities, incurrences of debt or other financings and payments of distributions. In addition, the existence of a controlling group (if one were to form) may have the effect of making it difficult for, or may discourage or delay, a third party from seeking to acquire us, which may adversely affect the market price of our common units. Further, conflicts of interest may arise between us and other entities for which members of the Davison family serve as officers or directors. In resolving any conflicts that may arise, such members of the Davison family may favor the interests of another entity over our interests.

Members of the Davison family own, control and have interests in diverse companies, some of which may (or could in the future) compete directly or indirectly with us. As a result, the interests of the members of the Davison family may not always be consistent with our interests or the interests of our other unitholders. Members of the Davison family could also pursue acquisitions or business opportunities that may be complementary to our business. Our organizational documents allow the holders of our units (including affiliates, like the Davisons) to take advantage of such corporate opportunities without first presenting such opportunities to us. As a result, corporate opportunities that may benefit us may not be available to us in a timely manner, or at all. To the extent that conflicts of interest may arise among us and any member of the Davison family, those conflicts may be resolved in a manner adverse to us or you. Other potential conflicts may involve, among others, the following situations:

- our general partner is allowed to take into account the interest of parties other than us, such as one or more of its affiliates, in resolving conflicts of interest;
- our general partner may limit its liability and reduce its fiduciary duties, while also restricting the remedies available to our unitholders for actions that, without such limitations, might constitute breaches of fiduciary duty;
- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional partnership securities, reimbursements and enforcement of obligations to the general partner and its affiliates, retention of counsel, accountants and service providers and cash reserves, each of which can also affect the amount of cash that is distributed to our unitholders; and
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us and the reimbursement of these costs and of any services provided by our general partner could adversely affect our ability to pay cash distributions to our unitholders.

Our Class B Common Units may be transferred to a third party without unitholder consent, which could affect our strategic direction.

Unlike the holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Only holders of our Class B Common Units have the right to elect our board of directors. Holders of our Class B Common Units may transfer such units to a third party without the consent of the unitholders. The new holders of our Class B Common Units may then be in a position to replace our board of directors and officers of our general partner with its own choices and to control the strategic decisions made by our board of directors and officers.

Unitholders with registration rights have rights to require underwritten offerings that could limit our ability to raise capital in the public equity market.

Unitholders with registration rights have rights to require us to conduct underwritten offerings of our common units. If we want to access the capital markets (debt and equity), those unitholders' ability to sell a portion of their common units could satisfy investor's demand for our common units or may reduce the market price for our common units, thereby reducing the net proceeds we would receive from a sale of newly issued units.

We may issue additional common units without unitholder's approval, which would dilute their ownership interests.

We may issue an unlimited number of limited partner interests of any type without the approval of our unitholders. The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of our common units may decline.

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

If at any time our general partner and its affiliates own more than 80% of any class of our units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates, including any controlling unitholder, or to

Table of Contents

us, to acquire all, but not less than all, of the units held by unaffiliated persons at a price not less than their then-current market price. As a result, unitholders may be required to sell their units at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon a sale of their units.

The interruption of distributions to us from our subsidiaries and joint ventures could affect our ability to make payments on indebtedness or cash distributions to our unitholders.

We are a holding company. As such, our primary assets are the equity interests in our subsidiaries and joint ventures. Consequently, our ability to fund our commitments (including payments on our indebtedness) and to make cash distributions depends upon the earnings and cash flow of our subsidiaries and joint ventures and the distribution of that cash to us. Distributions from our joint ventures are subject to the discretion of their respective management committees. Further, certain joint ventures' charter documents may vest in their management committees' certain discretion regarding cash distributions. Accordingly, our joint ventures may not continue to make distributions to us at current levels or at all.

We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.

Unlike a corporation, our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash reduced by any amounts reserved for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our units and other limited partner interests may decrease in direct correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue more equity to recapitalize.

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

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to 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 an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable both for the obligations of the assignor to make contributions to the partnership that were known to the substituted limited partner at the time it became a limited partner and for those obligations that were unknown if the liabilities could have been determined from the partnership agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted.

Unitholder 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. Our partnership is organized under Delaware law, and we conduct business in 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 states in which we do business or may do business in from time to time in the future. Unitholders could be liable for any and all of our obligations as if unitholders were a general partner if a court or government agency were to determine that:

- we were conducting business in a state but had not complied with that particular state's partnership statute; or
- unitholders 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 constitutes "control" of our business.

Tax Risks to Our Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as us not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service, or IRS, were to treat us as a corporation (for U.S. federal income tax purposes) or if we were to become subject to a material amount of entity-level taxation for state tax purposes, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. Section 7704 of the Internal Revenue Code provides that publicly traded partnerships will, as a general rule, be taxed as corporations. However, an exception, referred to in this discussion as the “Qualifying Income Exception,” exists with respect to publicly traded partnerships, 90% or more of the gross income of which for each taxable year consists of “qualifying income.”

Table of Contents

If less than 90% of our gross income for any taxable year is "qualifying income" from transportation, processing or marketing of natural resources (including minerals, crude oil, natural gas or products thereof), interest or dividends income, we will be taxable as a corporation under Section 7704 of the Internal Revenue Code for federal income tax purposes for that taxable year and all subsequent years. We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes.

The decision of the U.S. Court of Appeals for the Fifth Circuit in Tidewater Inc. v. U.S., 565 F.3d 299 (5th Cir. April 13, 2009) held that the marine time charter being analyzed in that case was a "lease" that generated rental income rather than income from transportation services for purposes of a foreign sales corporation provision of the Internal Revenue Code. Even though (i) the Tidewater case did not involve a publicly traded partnership and it was not decided under Section 7704 of the Internal Revenue Code relating to "qualifying income," (ii) some experienced practitioners believe the decision was not well reasoned, (iii) the IRS stated in an Action on Decision (AOD 2010-01) that it disagrees with and will not acquiesce to the Fifth Circuit's marine time charter analysis contained in the Tidewater case and (iv) the IRS has issued several favorable private letter rulings (which can be relied upon and cited as precedent by only the taxpayers that obtained them) relating to time charters since the Tidewater decision was issued, the Tidewater decision creates some uncertainty regarding the status of income from certain of our marine time charters as "qualifying income" under Section 7704 of the Internal Revenue Code. Notwithstanding the foregoing, the Tidewater case is relevant authority because it is the only case of which we and our outside tax counsel are aware directly analyzing whether a particular time charter would constitute a lease or service agreement for certain U.S. federal tax purposes. Due to the uncertainty created by the Tidewater decision, our outside tax counsel, Akin Gump Strauss Hauer & Feld, LLP, was required to change the standard in its opinion relating to our status as a partnership for federal income tax purposes to "should" from "will."

Although we do not believe based upon our current operations that we are 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 a maximum of 21% and would pay state income tax at varying rates. Distributions to our unitholders would generally be taxable to them again as corporate distributions and no income, gains, losses, or deductions would flow through to them. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay Texas franchise tax on our gross income apportioned to Texas. Imposition of any such taxes on us by any other state would reduce our cash available for distribution to our unitholders.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. From time to time, members of Congress propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships. Although there is no current legislative proposal, a prior legislative proposal would have eliminated 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.

Any modifications to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could cause a material reduction in our anticipated cash flows and could cause us to be treated as an association taxable as a corporation for U.S. federal income tax purposes subjecting us to

the entity-level tax and adversely affecting the value of our common units.
A successful IRS contest of the federal income tax positions we take may adversely affect the market for our common units, and the costs of any IRS contest would reduce our cash available for distribution to our unitholders and our general partner.
The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because these costs will reduce our cash available for distribution.

Table of Contents

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us. To the extent possible under the new rules, our general partner may elect to either cause us to pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised information statement to each unitholder and former unitholder with respect to an audited and adjusted return. Although our general partner may elect to have it, our unitholders and former unitholders take such audit adjustments into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. If we make payments of taxes and any penalties and interest directly to the IRS in the year in which the audit is completed, our cash available for distribution to our unitholders might be substantially reduced, in which case our current unitholders may bear some or all of the tax liability resulting from such audit adjustments, even if such unitholders did not own common units in us during the tax year under audit.

Our unitholders will be required to pay taxes on income (as well as deemed distributions, if any) from us even if they do not receive any cash distributions from us.

Our unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income (as well as deemed distributions, if any) even if unitholders receive no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income (or deemed distributions, if any) or even the tax liability that results from that income (or deemed distribution).

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

If our unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of their allocable share of our net taxable income decrease their tax basis in their 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. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder’s share of our non-recourse liabilities, if our unitholders sell their common units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

Unitholders may be subject to limitations on their ability to deduct interest expense 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 Tax Cuts and Jobs Act (the "Tax Act"), for taxable years beginning after December 31, 2017, our deduction for "business interest" is limited to the sum of our business interest income plus 30% of our "adjusted taxable income." Recently issued proposed regulations adopt a broad definition of interest, treating certain amounts (including income, deduction, gain, or loss from certain derivative instruments that alter our effective cost of borrowing) as business interest subject to the limitation. For the 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 (other than depreciation, amortization, or depletion capitalized to inventory). Any interest disallowed may be carried forward and deducted in future years by the unitholder from his share of our "excess taxable income," which is generally equal to the excess of 30% of our adjusted taxable income over the amount of our deduction for business interest for such future taxable year, subject to certain restrictions. While actual results may differ from the current estimates, we anticipate that our deduction for business interest will be limited under the interest expense limitations. If this limitation were to apply with respect to a taxable year, it could result in an increase in the taxable income allocable to a unitholder for such taxable year without any corresponding increase in the cash available for distribution to such unitholder.

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 individual retirement accounts (known as IRAs), other retirement plans and non-U.S. persons, raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Allocations and/or distributions to non-U.S. persons will be subject to withholding taxes at the highest applicable effective tax rate and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. Tax-exempt entities and non-U.S. persons should consult their tax advisors before investing in our common units.

Table of Contents

Recently enacted legislation provides that if a unitholder sells or otherwise disposes of a common unit, the transferee is required to withhold 10% 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 IRS has 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 our common units as having the same tax benefits without regard to the common units actually purchased. The IRS may challenge this treatment, which could adversely affect the value of our common units.

Because we cannot match transferors and transferees of our common units, we adopt depreciation and amortization conventions that may not conform to all aspects of existing Treasury Regulations and may result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions. A successful IRS challenge to those conventions could adversely affect the amount of tax benefits available to a common unitholder. It also could affect the timing of these tax benefits or the amount of gain from a sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the common unitholder's tax returns.

Our unitholders will likely be subject to state and local taxes in states where they do not live as a result of an investment in the common units.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if our unitholders do not live in any of those jurisdictions. Our unitholders will likely be required to file foreign, state, and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We own assets and do business in more than 20 states including Texas, Louisiana, Mississippi, Alabama, Florida, Arkansas and Oklahoma. Many of the states we currently do business in impose a personal income tax. It is our unitholders' responsibility to file all applicable U.S. federal, foreign, state and local tax returns.

We have subsidiaries that are treated as corporations for federal income tax purposes and subject to corporate-level income taxes.

We conduct a portion of our operations through subsidiaries that are, or are treated as, corporations for federal income tax purposes. We may elect to conduct additional operations in corporate form in the future. These corporate subsidiaries will be subject to corporate-level tax, which, effective for taxable years beginning after December 31, 2017, is 21%, 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 us and, in turn, to our unitholders. If the IRS were to successfully assert that these corporate subsidiaries have more tax liability than we anticipate or legislation was enacted that increased the corporate tax rate, our cash available for distribution to our unitholders would be further reduced.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred.

We prorate our items of income, gain, loss, and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month (the Allocation Date), instead of on the basis of the date a particular unit is transferred. Similarly, we generally allocate certain deductions for depreciation of capital additions, gain or loss realized on a sale or other disposition of our assets and, in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. The U.S. Department of the Treasury adopted final Treasury Regulations allowing a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to challenge our proration method, we may be required to change the allocation of

items of income, gain, loss and deduction among our unitholders.
A unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of those units. If so, such unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.
Because a unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of the loaned units, such unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and 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 units

Table of Contents

may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

## Item 1B. Unresolved Staff Comments

None.

## Item 2. Properties

See Item 1. "Business." We also have various operating leases for rental of office space, office and field equipment and vehicles. See "Commitments and Off-Balance Sheet Arrangements" in Management's Discussion and Analysis of Financial Condition and Results of Operations, and Note 22 to our Consolidated Financial Statements in Item 8 for the future minimum rental payments. Such information is incorporated herein by reference.

## Item 3. Legal Proceedings

We are involved from time to time in various claims, lawsuits and administrative proceedings incidental to our business. In our opinion, the ultimate outcome, if any, of such proceedings is not expected to have a material adverse effect on our financial condition, results of operations or cash flows. See Note 22 to our Consolidated Financial Statements in Item 8.

## Item 4. Mine Safety Disclosures

Information regarding mine safety and other regulatory action at our mine in Green River, Wyoming is included in Exhibit 95 to this Form 10-K.

Table of Contents

PART II

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

Our Class A common units are listed on the New York Stock Exchange, or NYSE, under the symbol “GEL.”

At February 28, 2019, we had 122,539,221 Class A common units outstanding. As of December 31, 2018, the closing price of our common units was $18.47 and we had approximately 28,000 record holders of our Class A common units, which include holders who own units through their brokers “in street name.” Additionally, we have issued 24,438,022 Class A Convertible Preferred Units for which there is no established public trading market.

Available cash generally means, for each fiscal quarter, all cash on hand at the end of the quarter:

- less the amount of cash reserves that our general partner determines in its reasonable discretion is necessary or appropriate to:
- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments, or other agreements; or
- provide funds for distributions to our unitholders for any one or more of the next four quarters;
- plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings. Working capital borrowings are generally borrowings that are made under our credit facility and in all cases are used solely for working capital purposes or to pay distributions to partners.

The full definition of available cash is set forth in our partnership agreement and amendments thereto, which are incorporated by reference as an exhibit to this Form 10-K.

See Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Capital Expenditures and Distributions Paid to our Unitholders” and Note 12 to our Consolidated Financial Statements in Item 8 for further information regarding restrictions on our distributions. See Item 12. “Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters” for information regarding securities authorized for issuance under equity compensation plans.

Table of Contents

Item 6. Selected Financial Data

The table below includes selected financial and other data for the Partnership for the years ended December 31, 2018, 2017, 2016, 2015 and 2014 (in thousands, except per unit and volume data). The selected financial data should be read in conjunction with our Consolidated Financial Statements and Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

Table of Contents

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2018 (1) | 2017 (1) | 2016 (1) | 2015 (1) | 2014 (1) |
| Income Statement Data: | | | | | |
| Revenues: | | | | | |
| Offshore pipeline transportation | 284,544 | 318,239 | 334,679 | 140,230 | 3,296 |
| Sodium minerals and sulfur services | 1,174,434 | 462,622 | 171,503 | 177,880 | 207,401 |
| Marine transportation | 219,937 | 205,287 | 213,021 | 238,757 | 229,282 |
| Onshore facilities and transportation | 1,233,855 | 1,042,229 | 993,290 | 1,689,662 | 3,406,185 |
| Total revenues | $2,912,770 | $2,028,377 | $1,712,493 | $2,246,529 | $3,846,164 |
| Equity in earnings of equity investees | $43,626 | $51,046 | $47,944 | $54,450 | $43,135 |
| Income (loss) from continuing operations after income taxes | $(11,792) | $82,079 | $111,082 | $421,585 | $106,202 |
| Net income (loss) attributable to Genesis Energy, L.P. | $(6,075) | $82,647 | $113,249 | $422,528 | $106,202 |
| Net income (loss) available to Common Unitholders | $(75,876) | $60,652 | $113,249 | $422,528 | $106,202 |
| Net income (loss) attributable to Common Unitholders per Common Unit: Basic and Diluted | $(0.62) | $0.50 | $1.00 | $4.10 | $1.18 |
| Cash distributions declared per Common Unit | $2.1000 | $2.6525 | $2.7175 | $2.4700 | $2.2300 |
| Balance Sheet Data (at end of period): | | | | | |
| Current assets | $443,279 | $636,033 | $359,569 | $306,316 | $355,366 |
| Total assets (2) | $6,479,071 | $7,137,481 | $5,702,592 | $5,459,599 | $3,210,624 |
| Long-term liabilities (2) | $3,704,237 | $3,966,602 | $3,321,739 | $3,136,712 | $1,618,276 |
| Class A Convertible Preferred Units | $761,466 | $697,151 | $— | $— | $— |
| Partners' capital: | | | | | |
| Common unitholders | 1,690,799 | 2,026,147 | 2,130,331 | 2,029,101 | 1,229,203 |
| Accumulated Other Comprehensive Income (Loss) | 939 | (604) | — | — | — |
| Noncontrolling interests | (11,204) | (8,079) | (10,281) | (8,350) | — |
| Total partners' capital | $1,680,534 | $2,017,464 | $2,120,050 | $2,020,751 | $1,229,203 |
| Other Data: | | | | | |
| Volumes: | | | | | |
| Offshore crude oil pipeline (barrels per day) | 562,467 | 591,667 | 581,763 | 518,211 | 446,548 |
| Onshore crude oil pipeline (barrels per day) | 247,409 | 212,768 | 114,130 | 144,084 | 116,225 |
| Natural gas transportation volumes (MMBtus/d) | 432,261 | 496,302 | 679,862 | 708,556 | — |
| $CO_2$ pipeline (Mcf per day) | 107,674 | 77,921 | 97,955 | 161,409 | 173,770 |
| NaHS sales (DST) | 150,671 | 133,404 | 125,766 | 127,063 | 150,038 |
| Soda Ash volumes (short tons sold) | 3,669,206 | 1,274,421 | — | — | — |
| NaOH sales (DST) | 110,107 | 84,816 | 80,021 | 86,914 | 94,693 |
| Crude oil and petroleum products sales (barrels per day) | 45,845 | 51,771 | 62,484 | 91,704 | 99,139 |

Table of Contents

(1) Our operating results and financial position have been affected by acquisitions and divestitures. For additional information regarding our acquisitions and divestitures during 2018, 2017 and 2016, see Note 4, related to our acquisitions, and Note 7, related to our divestitures, to our Consolidated Financial Statements included in Item 8.

(2) As relating to new accounting guidance issued by the FASB which we adopted in 2015, our long-term liabilities and total assets for the years 2015 and after are presented to reflect changes in presentation of debt issuance costs as a direct reduction of related debt liabilities with amortization of debt issuance costs reported as interest expense. Prior to 2015, our debt liabilities were presented as a component of other long term assets.

(3) As a result of the adoption of the new revenue recognition 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.

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

### Introduction

We are a growth-oriented master limited partnership formed in Delaware in 1996. Our common units are traded on the New York Stock Exchange, or NYSE, under the ticker symbol "GEL." We are (i) a provider of an integrated suite of midstream services - primarily transportation, storage, sulfur removal, blending, terminalling and processing-for a large area of the Gulf Coast region of the crude oil and natural gas industry and (ii) one of the leading producers in the world of natural soda ash. Our sulfur removal business results in us being the largest producer, we believe, in the world of sodium hydrosulfide (or NaHS, pronounced "nash").

Historically, a substantial majority of our focus has been on the midstream segment of the crude oil and natural gas industry in the Gulf Coast region of the United States and in the Gulf of Mexico. We provide an integrated suite of services to refiners, crude oil and natural gas producers, and industrial and commercial enterprises and have a diverse portfolio of assets, including pipelines, offshore hub and junction platforms, refinery-related plants, storage tanks and terminals, railcars, rail loading and unloading facilities, barges and other vessels, and trucks.

On September 1, 2017, we acquired our trona and trona-based exploring, mining, processing, producing, marketing and selling business based in Wyoming (our "Alkali Business") for approximately $1.325 billion in cash. Our Alkali Business mines and processes trona from which it produces natural soda ash, also known as sodium carbonate ($Na_2CO_3$), a basic building block for a number of ubiquitous products, including flat glass, container glass, dry detergent and a variety of chemicals and other industrial products. Our Alkali Business has a diverse customer base in the United States, Canada, the European Community, the European Free Trade Area and the South African Customs Union with many long-term relationships. It has been operating for almost 70 years and has an estimated remaining reserve life (based on 2018 production) of over 100 years.

Within our legacy midstream business, we have two distinct, complementary types of operations-(i) our offshore Gulf of Mexico crude oil and natural gas pipeline transportation and handling operations, which focus on providing a suite of services primarily to integrated and large independent energy companies who make intensive capital investments to develop numerous large-reservoir, long-lived crude oil and natural gas properties and (ii) our onshore-based refinery-centric operations located primarily in the Gulf Coast region of the U.S., which focus on providing a suite of services primarily to refiners, which includes our sulfur removal, transportation, storage, and other handling services. Our onshore-based operations occur upstream of, at, and downstream of refinery complexes. Upstream of refineries, we aggregate, purchase, gather and transport crude oil, which we sell to refiners. Within refineries, we provide services to assist in sulfur removal/balancing requirements. Downstream of refineries, we provide transportation services as well as market outlets for finished refined petroleum products and certain refining by-products. In our offshore crude oil and natural gas pipeline transportation and handling operations, we provide services to one of the most active drilling and development regions in the U.S.-the Gulf of Mexico, a producing region representing approximately 16% of the crude oil production in the U.S. in 2018. Our legacy midstream business has a diverse portfolio of customers, operations and assets, including pipelines, offshore hub and junction platforms, refinery-related plants, storage tanks and terminals, railcars, rail loading and unloading facilities, barges and other vessels, and trucks.

Included in Management's Discussion and Analysis are the following sections:

- Overview of 2018 Results
- Acquisitions, Divestitures and Growth Initiatives
- Results of Operations
- Other Consolidated Results
- Financial Measures
- Liquidity and Capital Resources
- Commitments and Off-Balance Sheet Arrangements
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements

Overview of 2018 Results

We reported Net Loss Attributable to Genesis Energy, L.P. of $6.1 million, or $0.62 per common unit, in 2018 compared to Net Income Attributable to Genesis Energy, L.P. of $82.6 million, or $0.50 per common unit, in 2017. The decrease was principally due to impairment expense of $126.3 million recognized during 2018. Additionally, we had an increase in depreciation and interest expense during 2018 of $60.7 million and $52.4 million, respectively, primarily attributable to owning our Alkali assets for a full year and the interest on the debt associated with that acquisition.

These decreases to net income were offset by an increase in our reported Segment Margin (as defined below in "Financial Measures") of $118.2 million principally due to twelve months of contribution from our Alkali Business during 2018 relative to four months during 2017 and the increase in volumes in our onshore facilities and transportation segment, primarily in Louisiana. Additionally, we recorded an unrealized gain of approximately $8.4 million associated with the valuation of our embedded derivative on our Class A Convertible Preferred Units recognized during 2018 compared to an unrealized loss reported in 2017 of approximately $10.5 million (both of which are recorded in Other income (expense) in the Consolidated Statements of Operations).

Cash flow from operating activities was $390.0 million for the 2018 period compared to $323.6 million for 2017, primarily driven by an increase in Segment Margin of $118.2 million during 2018 relative to 2017, partially offset by an increase in working capital effects of $12.3 million during 2018 relative to 2017.

Available Cash before Reserves (as defined below in "Financial Measures") increased $77.1 million in 2018 to $466.1 million as compared to 2017 Available Cash before Reserves of $389.0 million. See "Financial Measures" below for additional information on Available Cash before Reserves.

Segment Margin was $712.8 million in 2018, an increase of $118.2 million, or 20%, as compared to 2017. This increase resulted primarily from higher contributions from our sodium minerals and sulfur services segment (principally due to owning our Alkali Business for a full year in 2018 as compared to four months during 2017) and our onshore facilities and transportation segment, primarily attributable to our increased volumes during 2018 from our recently constructed assets in Louisiana and Texas, partially offset by smaller decreases in our other segments.

In 2018, we continued our path to de-leveraging our balance sheet and maintaining our financial flexibility to continue building long term value to stakeholders. We continued to find opportunities to right size our businesses and, during 2018, divested certain of our non-core assets to accelerate our goal to de-leverage our balance sheet. These steps, along with stable cash flows from our recently completed acquisition of our Alkali Business and the contribution from our recent strategic investments, we believe further enhance our financial flexibility to opportunistically pursue accretive organic projects and acquisitions should they present themselves. Additionally, we have situated ourselves well for future increases in volumes in our offshore business due to the long-lived reserves in the Gulf of Mexico that requires little or no additional investment from us. Overall, we believe these actions to strengthen our balance sheet and enhance our financial flexibility are the best actions we can take to allow us to generate strong optimal returns for our unitholders in the years ahead.

We currently manage our businesses through four divisions that constitute our reportable segments - offshore pipeline transportation, sodium minerals and sulfur services, onshore facilities and transportation and marine transportation.

A more detailed discussion of our segment results and other costs is included below in "Results of Operations".

Distributions to Unitholders

On February 14, 2019, we paid a distribution of $0.55 per unit related to the fourth quarter of 2018.

With respect to our Class A Convertible Preferred Units, we have declared a payment-in-kind or PIK of the quarterly distribution, which resulted in the issuance of an additional 534,576 Class A Convertible Preferred Units. This PIK amount equates to a distribution of $0.7374 per Class A Convertible Preferred Unit for the 2018 Quarter, or $2.9496 annualized. These distributions were paid on February 14, 2019 to unitholders holders of record at the close of business January 31, 2019.

Acquisitions, Divestitures and Growth Initiatives

Alkali Business Acquisition

On September 1, 2017, we acquired our trona and trona-based exploring, mining, processing, producing, marketing and selling business based in Wyoming (our “Alkali Business”) for approximately $1.325 billion in cash. During 2018, we continued to integrate the Alkali business and the results of the business have exceeded our expectations to date.

Table of Contents

Baton Rouge Area Infrastructure Expansion
We expanded our existing Baton Rouge area infrastructure to allow for greater capacity and flexibility in servicing our major refinery customer in the region. This expansion included the construction of an additional 500,000 barrels of crude oil tankage at our existing Baton Rouge Terminal. Additionally, this expansion included the upgrading of pumping and other infrastructure capabilities in order to allow for the efficient handling of expected increases in crude oil volumes received at our Baton Rouge area facilities. These assets became operational in the first half of 2018.
Powder River Basin Midstream Assets Divestiture

On October 11, 2018, we completed the divestiture of our Powder River Basin midstream assets and received total net proceeds of approximately $300 million that we utilized to reduce the balance outstanding under our revolving credit facility.
Results of Operations
In the discussions that follow, we will focus on our revenues, expenses and net income, as well as two measures that we use to manage the business and to review the results of our operations-Segment Margin and Available Cash before Reserves. Segment Margin and Available Cash before Reserves are defined in the "Financial Measures" section below.
Revenues, Costs and Expenses
Our revenues for the year ended December 31, 2018 increased $884.4 million, or 44%, from the year ended December 31, 2017. Additionally, our costs and expenses (excluding gains on sale of assets and impairment expense) increased $810.4 million, or 45%, between the two periods. These increases are primarily attributable to the effects of a full year of results from our Alkali Business during 2018, along with the increase in crude oil prices during 2018 that proportionately impacted our revenues and cost of sales.
The addition of our Alkali Business resulted in a large increase in revenues and costs relative to 2017 (which are reflected in our sodium minerals and sulfur services segment). Those increases are principally derived from mining trona ore and processing the entrained mineral sodium carbonate, also known as naturally occurring soda ash. Natural soda ash has significant cost advantages over synthetically produced soda ash, which we believe will exist for the foreseeable future. Natural soda ash accounts for only about 25% of the world's production; thus, we believe we should be able to somewhat mitigate the effects of market-specific factors (e.g., changes in sales prices for our products, our operating costs, and other economic considerations) on Net Income(loss), Available Cash before Reserves, and Segment Margin in the soda ash market in which we operate.
In addition to our Alkali Business, we continue to operate in our other legacy businesses, including: (i) our offshore Gulf of Mexico crude oil and natural gas pipeline transportation and handling operations, focusing on integrated and large independent energy companies who make intensive capital investments (often in excess of billions of dollars) to develop numerous large reservoir, long-lived crude oil and natural gas properties; and (ii) our onshore-based refinery-centric operations located primarily in the Gulf Coast region of the U.S., which focus on providing a suite of services primarily to refiners. Refiners are the shippers of approximately 80% of the volumes transported on our onshore crude pipelines, and refiners contract for over 80% of the use of our inland barges, which are used primarily to transport intermediate refined products (not crude oil) between refining complexes. The shippers on our offshore pipelines are mostly integrated and large independent energy companies whose production is ideally suited for the vast majority of refineries along the Gulf Coast, unlike the lighter crude oil and condensates produced from numerous onshore shale plays. Their large-reservoir properties and the related pipelines and other infrastructure needed to develop them are capital intensive and yet, we believe, economically viable, in most cases, even in relatively low commodity price environments. Given these facts, we do not expect changes in commodity prices to impact our Net Income(loss), Available Cash before Reserves or Segment Margin derived from our offshore Gulf of Mexico crude oil and natural gas pipeline transportation and handling operations in the same manner in which they impact our revenues and costs derived from the purchase and sale of crude oil and petroleum products.
A substantial portion of our revenues and costs are derived from the purchase and sale of crude oil and petroleum products through our onshore facilities and transportation segment. In addition, our revenues and costs between these

two periods have been impacted by increases in market prices associated with our crude oil and petroleum product sales as discussed further below. In general, we do not expect fluctuations in prices for crude oil and natural gas to materially affect our net income, Available Cash before Reserves or Segment Margin to the same extent they affect our revenues and costs. We have limited our direct commodity price exposure in our crude oil and petroleum products operations through the broad use of fee-based service contracts, back-to-back purchase and sale arrangements, and hedges. As a result, changes in the price of crude oil

Table of Contents

would proportionately impact both our revenues and our costs, with a disproportionately smaller net impact on our Segment Margin.

As discussed throughout this document, we have some indirect exposure to certain changes in prices for oil and petroleum products, particularly if they are significant and extended. We tend to experience more demand for certain of our services when prices increase significantly over extended periods of time, and we tend to experience less demand for certain of our services when prices decrease significantly over extended periods of time. For additional information regarding certain of our indirect exposure to commodity prices, see our segment-by-segment analysis below and the previous section entitled “Risks Related to Our Business”.

Prices of crude oil have increased since December 31, 2017. The average closing prices for West Texas Intermediate ("WTI") crude oil on the New York Mercantile Exchange ("NYMEX") increased 27% to $64.74 per barrel on a year to date average for 2018, as compared to $50.95 per barrel for 2017. We would expect changes in crude oil prices to continue to proportionately affect our revenues and costs attributable to our purchase and sale of crude oil and petroleum products, producing minimal direct impact on Segment Margin from those operations. However, due to the indirect exposure to changes in prices discussed above and in the discussion surrounding our onshore facilities and transportation segment, crude oil and petroleum product sales volumes decreased 11% in 2018 as compared to 2017. Additionally, changes in certain of our operating costs between the respective periods, including those associated with our offshore pipeline and marine transportation segments, are not directly correlated with commodity prices. We discuss certain of those costs in further detail below in our segment-by-segment analysis.

Included below is additional detailed discussion of the results of our operations focusing on Segment Margin and other costs including general and administrative expenses, depreciation and amortization, interest and income taxes.

Segment Margin

The contribution of each of our segments to total Segment Margin in each of the last three years was as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | (in thousands) | | |
| Offshore pipeline transportation | 285,014 | 317,540 | 336,620 |
| Sodium minerals and sulfur services | 260,488 | 130,333 | 79,508 |
| Onshore facilities and transportation | 119,918 | 96,376 | 83,364 |
| Marine transportation | 47,338 | 50,294 | 70,079 |
| Total Segment Margin | $712,758 | $594,543 | $569,571 |

Table of Contents

Year Ended December 31, 2018 Compared with Year Ended December 31, 2017

Offshore Pipeline Transportation Segment

Operating results and volumetric data for our offshore pipeline transportation segment are presented below:

| | Year Ended December 31, | |
|---|---|---|
| | 2018 | 2017 |
| | (in thousands) | |
| Offshore crude oil pipeline revenue, excluding non-cash revenues | $ 243,049 | $ 267,658 |
| Offshore natural gas pipeline revenue, excluding non-cash revenues | 47,048 | 50,582 |
| Offshore pipeline operating costs, excluding non-cash expenses | (57,256) | (63,231) |
| Distributions from equity investments[1] | 70,072 | 80,639 |
| Other | (17,899) | (18,108) |
| Offshore pipeline transportation Segment Margin | $ 285,014 | $ 317,540 |
| | | |
| Volumetric Data 100% basis: | | |
| Crude oil pipelines (average barrels/day unless otherwise noted): | | |
| CHOPS | 202,121 | 213,527 |
| Poseidon | 234,960 | 253,547 |
| Odyssey | 115,239 | 116,408 |
| GOPL [2] | 10,147 | 8,185 |
| Total crude oil offshore pipelines | 562,467 | 591,667 |
| | | |
| Natural gas transportation volumes (MMBtus/d) | 432,261 | 496,302 |
| | | |
| Volumetric Data net to our ownership interest [3]: | | |
| Crude oil pipelines (average barrels/day unless otherwise noted): | | |
| CHOPS | 202,121 | 213,527 |
| Poseidon | 150,374 | 162,270 |
| Odyssey | 33,419 | 33,758 |
| GOPL [2] | 10,147 | 8,185 |
| Total crude oil offshore pipelines | 396,061 | 417,740 |
| | | |
| Natural gas transportation volumes (MMBtus/d) | 164,706 | 222,729 |

(1) Offshore pipeline transportation Segment Margin includes distributions received from our offshore pipeline joint ventures accounted for under the equity method of accounting in 2018 and 2017, respectively.

(2) One of our wholly-owned subsidiaries (GEL Offshore Pipeline, LLC, or "GOPL") owns our undivided interest in the Eugene Island pipeline system.

(3) Volumes are the product of our effective ownership interest throughout the year, including changes in ownership interest, multiplied by the relevant throughput over the given year.

Offshore Pipeline Transportation Segment Margin for 2018 decreased $32.5 million, or 10%, from 2017, primarily due to lower volumes. During 2018, we experienced a greater amount of scheduled and unscheduled downtime at several of the production facilities connected to our offshore infrastructure. Additionally, during 2018, three particular major fields underperformed our expectations. Offsetting this in future years are two subsea tie-backs to the same dedicated in-field production facility scheduled to come on-line during the second half of 2019, which requires minimal to no additional capital investment from the partnership. We believe that one of the fields is underperforming as a result of reservoir quality degradation, and not due to mechanical factors. We believe that the other two large underperforming fields are predominately underperforming as the result of slower production rates than those that were communicated to us last year due to the operator's

Table of Contents

reserve recovery maximization efforts. Notwithstanding these short term negatives, we are currently seeing increasing demand for our assets from production that is currently dedicated to 3rd party pipelines but is unable to get to shore due to a lack of capacity on such pipelines. Given our excess capacity and connectivity on certain of our systems, we expect to benefit from this takeaway capacity constraint in future periods.

In addition, the minimum bill reservation fees we collect on one of our offshore oil pipelines had a prior year step down, and we collected approximately $4.4 million less in segment margin in 2018 relative to 2017. Lastly, 2017 included contributions of approximately $2.0 million from certain of our previously owned gas pipeline and platform assets that were divested during the second quarter of 2017.

Sodium Minerals and Sulfur Services Segment

Operating results for our sodium minerals and sulfur services segment were as follows:

| | Year Ended December 31, 2018 | 2017 |
|---|---|---|
| Volumes sold : | | |
| NaHS volumes (Dry short tons "DST") | 150,671 | 133,404 |
| Soda Ash volumes (short tons sold) (1) | 3,669,206 | 1,274,421 |
| NaOH (caustic soda) volumes (dry short tons sold) (1) | 110,107 | 84,816 |
| Total | 3,929,984 | 1,492,641 |
| | | |
| Revenues (in thousands): | | |
| NaHS revenues, excluding non-cash revenues | $181,391 | $149,392 |
| NaOH (caustic soda) revenues | 61,344 | 42,725 |
| Revenues associated with Alkali Business | 829,023 | 273,288 |
| Other revenues | 7,020 | 5,384 |
| Total external segment revenues, excluding non-cash revenues | $1,078,778 | $470,789 |
| | | |
| Sodium minerals and sulfur services operating costs, excluding non-cash items | (818,290) | (340,456) |
| | | |
| Segment Margin (in thousands) | $260,488 | $130,333 |
| | | |
| Average index price for NaOH per DST (2) | $768 | $635 |

(1) Includes sales volumes from September 1, 2017, the date on which we acquired our Alkali Business.

(2) Source: IHS Chemical

Sodium minerals and sulfur services Segment Margin for 2018 increased $130.2 million, or 100%, from 2017. This increase is principally due to the inclusion of contributions from our Alkali Business for twelve months during 2018 compared to four months during 2017, beginning with the acquisition date of September 1, 2017. The contributions thus far from our Alkali Business have exceeded our expectations and we expect continued strong performance into 2019. Costs impacting the results of our Alkali Business, many of which are similar in nature to costs related to our sulfur removal business, include costs associated with processing and producing soda ash (and other Alkali products) and marketing and selling activities. In addition, costs include activities associated with mining and extracting trona ore (including energy costs and employee compensation). Additionally, our refinery services business continues to perform well with increased NaHS volumes of approximately 13% during 2018 as they benefited from increased demand from certain of our international mining customers, primarily located in South America and our domestic mining and pulp and paper customers.

Onshore Facilities and Transportation Segment

Our onshore facilities and transportation segment utilizes an integrated set of pipelines and terminals, as well as trucks, railcars, and barges to facilitate the movement of crude oil and refined products on behalf of producers, refiners and other customers. This segment includes crude oil and refined products pipelines, terminals, rail facilities and $CO_2$ pipelines operating

58

Table of Contents

primarily within the United States Gulf Coast crude oil market. In addition, we utilize our railcar and trucking fleets that support the purchase and sale of gathered and bulk purchased crude oil, as well as purchased and sold refined products. Through these assets we offer our customers a full suite of services, including the following:

- facilitating the transportation of crude oil from producers to refineries and from owned and third party terminals to refiners via pipelines;
- transporting CO2 from natural and anthropogenic sources to crude oil fields owned by our customers;
- shipping crude oil and refined products to and from producers and refiners via trucks, railcars and pipelines;
- loading and unloading railcars at our crude-by-rail terminals;
- storing and blending of crude oil and intermediate and finished refined products;
- purchasing/selling and/or transporting crude oil from the wellhead to markets for ultimate use in refining; and
- purchasing products from refiners, transporting those products to one of our terminals and blending those products to a quality that meets the requirements of our customers and selling those products (primarily fuel oil, asphalt and other heavy refined products) to wholesale markets;

We also may use our terminal facilities to take advantage of contango market conditions for crude oil gathering and marketing and to capitalize on regional opportunities which arise from time to time for both crude oil and petroleum products.

Despite crude oil being considered a somewhat homogeneous commodity, many refiners are very particular about the quality of crude oil feedstock they process. Many U.S. refineries have distinct configurations and product slates that require crude oil with specific characteristics, such as gravity, sulfur content and metals content. The refineries evaluate the costs to obtain, transport and process their preferred feedstocks. That particularity provides us with opportunities to help the refineries in our areas of operation identify crude oil sources and transport crude oil meeting their requirements. The imbalances and inefficiencies relative to meeting the refiners' requirements may also provide opportunities for us to utilize our purchasing and logistical skills to meet their demands. The pricing in the majority of our crude oil purchase contracts contains a market price component and a deduction to cover the cost of transportation and to provide us with a margin. Contracts sometimes contain a grade differential which considers the chemical composition of the crude oil and its appeal to different customers. Typically, the pricing in a contract to sell crude oil will consist of the market price components and the grade differentials. The margin on individual transactions is then dependent on our ability to manage our transportation costs and to capitalize on grade differentials.

In our refined products marketing operations, we supply primarily fuel oil, asphalt and other heavy refined products to wholesale markets and some end-users such as paper mills and utilities. We also provide a service to refineries by purchasing "heavier" petroleum products that are the residual fuels from gasoline production, transporting them to one of our terminals and blending them to a quality that meets the requirements of our customers.

Table of Contents

Operating results for our onshore facilities and transportation segment were as follows:

| | Year Ended December 31, | |
|---|---|---|
| | 2018 | 2017 |
| | (in thousands) | |
| Gathering, marketing, and logistics revenue | $1,154,114 | $971,442 |
| Crude oil and $CO_2$ pipeline tariffs and revenues from direct financing leases of $CO_2$ pipelines | 74,895 | 67,226 |
| Payments received under direct financing leases not included in income | 7,633 | 6,921 |
| Crude oil and products costs, excluding unrealized gains and losses from derivative transactions | (1,038,386) | (866,239) |
| Operating costs, excluding non-cash charges for long-term incentive compensation and other non-cash expenses | (88,391) | (87,007) |
| Other | 10,053 | 4,033 |
| Segment Margin | $119,918 | $96,376 |
| | | |
| Volumetric Data (average barrels/day unless otherwise noted): | | |
| Onshore crude oil pipelines: | | |
| Texas | 33,303 | 32,684 |
| Jay | 14,036 | 14,155 |
| Mississippi | 6,359 | 8,290 |
| Louisiana (1) | 159,754 | 135,310 |
| Wyoming (2) | 33,957 | 22,329 |
| Onshore crude oil pipelines total | 247,409 | 212,768 |
| | | |
| $CO_2$ pipeline (average Mcf/day): | | |
| Free State | 107,674 | 77,921 |
| | | |
| Crude oil and petroleum products sales: | | |
| Total crude oil and petroleum products sales | 45,845 | 51,771 |
| Rail unload volumes (3) | 89,082 | 52,877 |

(1) Total daily volume for the years ended December 31, 2018 and December 31, 2017 includes 55,202 and 56,748 barrels per day respectively of intermediate refined products associated with our Port of Baton Rouge Terminal pipelines which became operational in the fourth quarter of 2016.

(2) The volumes presented for 2018 represent the average barrels/day through September 30, 2018, as the relevant assets were divested in October 2018.

(3) Includes total barrels for unloading at all rail facilities.

Segment Margin for our onshore facilities and transportation segment increased $23.5 million, or 24% , in 2018 as compared to 2017. The 2018 period includes the effects of the ramp up in volumes on our pipeline, rail and terminal infrastructure on our recently completed infrastructure in the Baton Rouge corridor. This was slightly offset by lower demand for our services in our historical back-to-back, or buy/sell, crude oil marketing business associated with aggregating and trucking crude oil from producers' leases to local or regional re-sale points. Additionally, while volumes were relatively constant on our Texas system between 2018 and 2017, we were able to recognize a full 12 months of minimum volume commitments in segment margin during 2018 compared to 7 months during 2017, as the expansion and re-purposing of our system was completed during the second quarter of 2017.

Marine Transportation Segment

Within our marine transportation segment, we own a fleet of 91 barges (82 inland and 9 offshore) with a combined transportation capacity of 3.2 million barrels, 42 push/tow boats (33 inland and 9 offshore), and a 330,000 barrel ocean going tanker, the M/T American Phoenix. Operating results for our marine transportation segment were as follows:

| | Year Ended December 31, | |
|---|---|---|
| | 2018 | 2017 |
| Revenues (in thousands): | | |
| Inland freight revenues | $93,091 | $82,354 |
| Offshore freight revenues | 70,804 | 73,540 |
| Other rebill revenues [1] | 56,042 | 49,393 |
| Total segment revenues | $219,937 | $205,287 |
| Operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses | $172,599 | $154,993 |
| Segment Margin (in thousands) | $47,338 | $50,294 |
| Fleet Utilization: [2] | | |
| Inland Barge Utilization | 95.2 % | 90.4 % |
| Offshore Barge Utilization | 93.5 % | 98.2 % |

(1) Under certain of our marine contracts, we "rebill" our customers for a portion of our operating costs.

(2) Utilization rates are based on a 365 day year, as adjusted for planned downtime and drydocking.

Marine Transportation Segment Margin for 2018 decreased $3.0 million, or 6%, from 2017. The decrease in Segment Margin is primarily attributable to our offshore barge fleet entering into short term spot price contracts, which can lead to a less favorable rebill structure and higher operating costs, as our last legacy term contract rolled off during the first quarter of 2018. Additionally, we had an increase in operating costs during 2018 relative to 2017 due to the increase in our dry-docking costs. We have continued to enter into short term contracts (less than a year) in both the inland and offshore markets because we believe the day rates currently being offered by the market are at, or approaching, cyclical lows. While we are reasonably hopeful that we've reached a bottom for the quarterly segment margin from our entire fleet of assets, we have no expectation of the fundamentals for marine transportation showing any significant improvement through at least the next several years. This excludes the M/T American Phoenix which is under long term contract through September 2020. These decreases were partially offset by increased segment margin in the 2018 period related to the M/T American Phoenix. During 2017, the M/T American Phoenix underwent its planned regulatory dry-docking inspections which negatively impacted segment margin. Additionally, the 2018 period also had higher utilization on our inland barge operation.

Other Costs and Interest

General and administrative expenses

| | Year Ended December 31, | |
|---|---|---|
| | 2018 | 2017 |
| | (in thousands) | |
| General and administrative expenses not separately identified below: | | |
| Corporate | $ 50,918 | $ 51,160 |
| Segment | 4,532 | 3,684 |
| Long-term incentive based compensation plan expense | 2,345 | (2,272) |
| Third party costs related to business development activities and growth projects | 9,103 | 13,849 |
| Total general and administrative expenses | $ 66,898 | $ 66,421 |

Total general and administrative expenses increased $0.5 million between 2018 and 2017. This is primarily attributable to an increase in our overall long term incentive compensation plan expense due to valuation assumptions used

Table of Contents

between the two periods. This increase was partially offset by lower third party financing, legal and accounting costs surrounding our acquisition and disposition activities in 2018 relative to 2017, including the acquisition of our Alkali Business.

Depreciation, depletion, and amortization expense

| | Year Ended December 31, | |
|---|---|---|
| | 2018 | 2017 |
| | (in thousands) | |
| Depreciation and depletion expense | $ 290,070 | $ 227,540 |
| Amortization of intangible assets | 21,835 | 23,612 |
| Amortization of $CO_2$ volumetric production payments | 1,285 | 1,328 |
| Total depreciation, depletion and amortization expense | $ 313,190 | $ 252,480 |

Total depreciation, depletion, and amortization expense increased $60.7 million between 2018 and 2017 primarily as a result of placing additional assets into service, including those acquired as a part of our Alkali Business and certain of our organic growth projects that were recently placed in service.

Interest expense, net

| | Year Ended December 31, | |
|---|---|---|
| | 2018 | 2017 |
| | (in thousands) | |
| Interest expense, senior secured credit facility (including commitment fees) | $ 62,439 | $ 51,587 |
| Interest expense, senior unsecured notes | 159,175 | 128,983 |
| Amortization and write-off of debt issuance costs and discount | 10,914 | 11,214 |
| Capitalized interest | (3,337 ) | (15,022 ) |
| Net interest expense | $ 229,191 | $ 176,762 |

Net interest expense increased $52.4 million during 2018 primarily due to an increase in our average outstanding indebtedness from acquired and constructed assets, including the financing of the acquisition of our Alkali Business in 2017, along with an increase in libor rates during 2018 which is a major component in the interest expense derived on our senior secured credit facility. In addition, capitalized interest decreased as result of certain of our large organic growth projects being completed and placed into service throughout 2017.

Other Consolidated Results

Net loss for the year ended December 31, 2018 included impairment expense of approximately $126.3 million recognized during 2018 including: (i) an impairment of $23.1 million on the goodwill associated with our supply and logistics reporting unit, which primarily consists of our legacy crude oil and refined products marketing and trucking businesses; (ii) an impairment of certain of our non-core offshore gas pipeline and platform assets of approximately $82.0 million for which the abandonment timing has accelerated; and (iii) a write-down of approximately $21.2 million related to our remaining non-core assets in the Powder River Basin(refer to Note 7 and Note 10).

Net income (loss) included an unrealized gain on the valuation of our embedded derivative associated with our preferred units of $8.4 million in 2018 compared to an unrealized loss of $10.5 million during 2017. Those amounts are included in other income (expense) in the Consolidated Statement of Operations.

Year Ended December 31, 2017 Compared with Year Ended December 31, 2016

Offshore Pipeline Transportation Segment

Operating results and volumetric data for our offshore pipeline transportation segment are presented below:

Table of Contents

| | Year Ended December 31, | |
|---|---|---|
| | 2017 | 2016 |
| | (in thousands) | |
| Offshore crude oil pipeline revenue | $ 267,658 | $ 270,454 |
| Offshore natural gas pipeline revenue | 50,582 | 64,225 |
| Offshore pipeline operating costs, excluding non-cash expenses | (63,231 ) | (72,009 ) |
| Distributions from equity investments | 80,639 | 84,321 |
| Other | (18,108 ) | (10,371 ) |
| Offshore Pipeline Transportation Segment Margin [1] | $ 317,540 | $ 336,620 |
| | | |
| Volumetric Data 100% basis: | | |
| Offshore crude oil pipelines (average barrels/day unless otherwise noted): | | |
| CHOPS | 213,527 | 204,533 |
| Poseidon | 253,547 | 262,829 |
| Odyssey | 116,408 | 106,933 |
| GOPL[2] | 8,185 | 7,468 |
| Total crude oil offshore pipelines | 591,667 | 581,763 |
| | | |
| Natural gas transportation volumes (MMBtus/d) | 496,302 | 679,862 |
| | | |
| Volumetric Data net to our ownership interest [3]: | | |
| Offshore crude oil pipelines (average barrels/day unless otherwise noted): | | |
| CHOPS | 213,527 | 204,533 |
| Poseidon | 162,270 | 168,211 |
| Odyssey | 33,758 | 31,011 |
| GOPL[2] | 8,185 | 7,468 |
| Total crude oil offshore pipelines | 417,740 | 411,223 |
| | | |
| Natural gas transportation volumes (MMBtus/d) | 222,729 | 398,190 |

(1) Offshore Pipeline Transportation Segment Margin includes distributions received from our offshore pipeline joint ventures accounted for under the equity method of accounting in 2017 and 2016, respectively.

(2) One of our wholly-owned subsidiaries (GEL Offshore Pipeline, LLC, or "GOPL") owns our undivided interest in the Eugene Island pipeline system.

(3) Volumes are the product of our effective ownership interest throughout the year, including changes in ownership interest, multiplied by the relevant throughput over the given year.

Offshore Pipeline Transportation Segment Margin for 2017 decreased $19.1 million, or 6%, from 2016. The year ended December 31, 2017 was negatively impacted by both anticipated and unanticipated downtime at several major fields, including weather-related downtime, affecting certain of our deepwater Gulf of Mexico customers and thus certain of our key crude oil and natural gas assets, including our Poseidon pipeline and certain associated laterals which we own. The 2017 period also reflects the effects of a contractual adjustment to a lower rate for a lateral we own that will be in place going forward. In addition, we benefited in 2016 from the temporary diversion of certain natural gas volumes from third party gas pipelines to one of our gas pipelines and related facilities due to one-time disruptions at onshore processing facilities where such volumes typically flow.

Table of Contents

Sodium Minerals and Sulfur Services Segment

Operating results for our sodium minerals and sulfur services segment were as follows:

| | Year Ended December 31, | |
|---|---|---|
| | 2017 | 2016 |
| Volumes sold: | | |
| NaHS volumes (Dry short tons "DST") | 133,404 | 125,766 |
| Soda Ash volumes (short tons sold) [(1)] | 1,274,421 | — |
| NaOH (caustic soda) volumes (dry short tons sold) [(1)] | 84,816 | 80,021 |
| Total | 1,492,641 | 205,787 |
| | | |
| Revenues (in thousands): | | |
| NaHS revenues | $149,392 | $136,240 |
| NaOH (caustic soda) revenues | 42,725 | 39,413 |
| Revenues associated with Alkali Business | 273,288 | — |
| Other revenues | 5,384 | 5,012 |
| Total external segment revenues | $470,789 | $180,665 |
| | | |
| Sodium minerals and sulfur services operating costs, excluding non-cash items | $(340,456) | $(101,157) |
| | | |
| Segment Margin (in thousands) | $130,333 | $79,508 |
| | | |
| Average index price for NaOH per DST [(2)] | $635 | $480 |

(1) Includes sales volumes from September 1, 2017, the date on which we acquired our Alkali Business.
(2) Source: IHS Chemical

Sodium minerals and sulfur services Segment Margin for 2017 increased $50.8 million, or 64%, from 2016. This increase is principally due to the inclusion of contributions from our Alkali Business since our acquisition date of September 1, 2017. The contributions thus far from our Alkali Business have exceeded our expectations and we expect continued strong performance into 2018 as we continue to remain the global leader in natural soda ash production. Costs impacting the results of our Alkali Business, many of which are similar in nature to costs related to our sulfur removal business, include costs associated with processing and producing soda ash (and other Alkali products) and marketing and selling activities. In addition, costs include activities associated with mining and extracting trona ore (including energy costs and employee compensation).

These contributions were partially offset by the results of our sulfur removal business and related NaHS and caustic soda activities. Our 2017 results for these activities were in line with our expectations and include the effects of previously disclosed commercial discussions with certain of our host refineries and several NaHS customers, which resulted in extending the term and tenor of a large number of contractual relationships.

Onshore Facilities and Transportation Segment

Operating results for our onshore facilities and transportation segment were as follows:

| | Year Ended December 31, | |
|---|---|---|
| | 2017 | 2016 |
| | (in thousands) | |
| Gathering, marketing, and logistics revenue | $971,442 | $930,347 |
| Crude oil and $CO_2$ tariffs and revenues from direct financing leases of $CO_2$ pipelines | 67,226 | 58,567 |
| Payments received under direct financing leases not included in income | 6,921 | 6,277 |
| Crude oil and products costs, excluding unrealized gains and losses from derivative transactions | (866,239 ) | (823,780 ) |
| Operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses | (87,007 ) | (94,592 ) |
| Other | 4,033 | 6,545 |
| Segment Margin | $96,376 | $83,364 |
| | | |
| Volumetric Data (average barrels/day unless otherwise noted): | | |
| Onshore crude oil pipelines: | | |
| Texas | 32,684 | 33,814 |
| Jay | 14,155 | 14,815 |
| Mississippi | 8,290 | 10,247 |
| Louisiana [(1)] | 135,310 | 44,295 |
| Wyoming | 22,329 | 10,959 |
| Onshore crude oil pipelines total | 212,768 | 114,130 |
| | | |
| $CO_2$ pipeline (average Mcf/day): | | |
| Free State | 77,921 | 97,955 |
| | | |
| Crude oil and petroleum products sales: | | |
| Total crude oil and petroleum products sales | 51,771 | 62,484 |
| Rail load/unload volumes [(2)] | 52,877 | 19,691 |

(1) Total daily volume for the years ended December 31, 2017 and December 31, 2016 includes 56,748 and 8,997 barrels per day respectively of intermediate refined products associated with our Port of Baton Rouge Terminal pipelines which became operational in the fourth quarter of 2016. Additionally, this includes 14,117 barrels per day for the year ended December 31, 2017 of crude oil associated with our new Raceland Pipeline which became fully operational in the second quarter of 2017.

(2) Includes total barrels for either loading or unloading at all rail facilities.

Segment Margin for our onshore facilities and transportation segment increased $13 million, or 16%, in 2017 as compared to 2016. The 2017 period includes the effects of the ramp up in volumes on our pipeline, rail and terminal infrastructure on our recently completed infrastructure in the Baton Rouge corridor. This was principally offset by lower demand for our services in our historical back-to-back, or buy/sell, crude oil marketing business associated with aggregating and trucking crude oil from producers' leases to local or regional re-sale points. In addition, the 2017 period was negatively impacted by lower volumes on our Texas pipeline system, as the repurposing of our Houston area crude oil pipeline and expansion of our terminal infrastructure did not became operational until the second quarter of 2017 (while a large portion of 2016 included historical volumes on our legacy Texas pipeline system assets prior to the repurposing project).

Table of Contents

Marine Transportation Segment

Operating results for our marine transportation segment were as follows:

| | Year Ended December 31, | |
|---|---|---|
| | 2017 | 2016 |
| Revenues (in thousands): | | |
| Inland freight revenues | $82,354 | $88,502 |
| Offshore freight revenues | 73,540 | 85,594 |
| Other rebill revenues (1) | 49,393 | 38,925 |
| Total segment revenues | $205,287 | $213,021 |
| | | |
| Operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses | $154,993 | $142,942 |
| | | |
| Segment Margin (in thousands) | $50,294 | $70,079 |
| | | |
| Fleet Utilization: (2) | | |
| Inland Barge Utilization | 90.4 % | 91.4 % |
| Offshore Barge Utilization | 98.2 % | 90.5 % |

(1) Under certain of our marine contracts, we "rebill" our customers for a portion of our operating costs.

(2) Utilization rates are based on a 365 day year, as adjusted for planned downtime and drydocking.

Marine Transportation Segment Margin for 2017 decreased $19.8 million, or 28% from 2016. The decrease in Segment Margin is primarily due to lower day rates on our inland and offshore fleets (which offset higher utilization as adjusted for planned dry docking time in our offshore fleet). The M/T American Phoenix also underwent planned regulatory dry docking inspections for approximately one month during 2017, which negatively impacted Segment Margin. In our inland fleet, weaker demand continued to apply pressure on our rates, which we expect to continue into 2018. In our offshore barge fleet, as a number of our units have come off longer term contracts, we have continued to choose to primarily place them in spot service or short-term (less than a year) service because we continue to believe the day rates currently being offered by the market are at, or approaching, cyclical lows.

Other Costs and Interest

General and administrative expenses

| | Year Ended December 31, | |
|---|---|---|
| | 2017 | 2016 |
| | (in thousands) | |
| General and administrative expenses not separately identified below: | | |
| Corporate | $ 51,160 | $ 35,841 |
| Segment | 3,684 | 3,264 |
| Equity-based compensation plan expense | (2,272) | 4,575 |
| Third party costs related to business development activities and growth projects | 13,849 | 1,945 |
| Total general and administrative expenses | $ 66,421 | $ 45,625 |

Total general and administrative expenses increased $21 million between 2017 and 2016. The increase is primarily attributable to the third party financing, legal and accounting costs surrounding our acquisition of our Alkali Business in 2017, as well as an increase in certain accruals made for a variety of items, including approximately $7.5 million relating to our annual bonus program. This was partially offset by the effects of changes in assumptions used to value our equity based compensation awards that are tied to our unit price.

Table of Contents

Depreciation and amortization expense

| | Year Ended December 31, | |
|---|---|---|
| | 2017 | 2016 |
| | (in thousands) | |
| Depreciation and depletion expense | $ 227,540 | $ 193,976 |
| Amortization of intangible assets | 23,612 | 24,310 |
| Amortization of $CO_2$ volumetric production payments | 1,328 | 3,910 |
| Total depreciation, depletion and amortization expense | $ 252,480 | $ 222,196 |

Total depreciation, depletion, and amortization expenses increased $30 million between 2017 and 2016 primarily as a result of placing additional assets into service, including those acquired as a part of our Alkali Business in 2017.

Interest expense, net

| | Year Ended December 31, | |
|---|---|---|
| | 2017 | 2016 |
| | (in thousands) | |
| Interest expense, senior secured credit facility (including commitment fees) | $ 51,587 | $ 41,948 |
| Interest expense, senior unsecured notes | 128,983 | 114,437 |
| Amortization and write-off of debt issuance costs and premium | 11,214 | 10,138 |
| Capitalized interest | (15,022 ) | (26,576 ) |
| Net interest expense | $ 176,762 | $ 139,947 |

Net interest expense increased $37 million during 2017 primarily due to an increase in our average outstanding indebtedness from acquired and constructed assets, including the financing of the acquisition of our Alkali Business in 2017. In addition, capitalized interest decreased as result of certain of our large organic growth projects being completed and placed into service throughout 2017.

Other Consolidated Results

Net income included an unrealized loss on derivative positions, excluding fair value hedges, of $10.9 million in 2017 and an unrealized loss of $1.3 million in 2016. Those amounts are included in onshore facilities and transportation product costs in the Consolidated Statement of Operations and are not a component of Segment Margin. Net income for the year ended December 31, 2017 also includes $40.3 million of gains resulting from the sale of certain non-core assets, as well as a $12.6 million non-cash provision relating to certain leased railcars no longer in use.

Financial Measures

Overview

This Annual Report on Form 10-K includes the financial measure of Available Cash before Reserves, which is a “non-GAAP” measure because it is not contemplated by or referenced in generally accepted accounting principles in the United States of America (GAAP). We also present total Segment Margin as if it were a non-GAAP measure. Our Non-GAAP measures may not be comparable to similarly titled measures of other companies because such measures may include or exclude other specified items. The accompanying schedules provide reconciliations of these non-GAAP financial measures to their most directly comparable financial measures calculated in accordance with GAAP. A reconciliation of Segment Margin to net income (loss) is included in our segment disclosures in Note 14 to our Consolidated Financial Statements in Item 8. Our non-GAAP financial measures should not be considered (i) as alternatives to GAAP measures of liquidity or financial performance or (ii) as being singularly important in any particular context; they should be considered in a broad context with other quantitative and qualitative information. Our Available Cash before Reserves and total Segment Margin measures are just two of the relevant data points considered from time to time.

When evaluating our performance and making decisions regarding our future direction and actions (including making discretionary payments, such as quarterly distributions) our board of directors and management team has access to a wide range of historical and forecasted qualitative and quantitative information, such as our financial statements; operational information; various non-GAAP measures; internal forecasts; credit metrics; analyst opinions; performance, liquidity and similar measures; income; cash flow expectations for us; and certain information regarding some of our peers. Additionally, our board of

Table of Contents

directors and management team analyze, and place different weight on, various factors from time to time. We believe that investors benefit from having access to the same financial measures being utilized by management, lenders, analysts and other market participants. We attempt to provide adequate information to allow each individual investor and other external user to reach her/his own conclusions regarding our actions without providing so much information as to overwhelm or confuse such investor or other external user. Our non-GAAP financial measures should not be considered as an alternative to GAAP measures such as net income, operating income, cash flow from operating activities or any other GAAP measure of liquidity or financial performance.

Segment Margin

We define Segment Margin as revenues less product costs, operating expenses, and segment general and administrative expenses, after eliminating gain or loss on sale of assets, plus or minus applicable Select Items. Although, we do not necessarily consider all of our Select Items to be non-recurring, infrequent or unusual, we believe that an understanding of these Select Items is important to the evaluation of our core operating results. Our chief operating decision maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including Segment Margin, segment volumes where relevant and capital investment.

A reconciliation of Segment Margin to net income (loss) is included in our segment disclosures in Note 14 to our Consolidated Financial Statements in Item 8.

Available Cash before Reserves

Purposes, Uses and Definition

Available Cash before Reserves, often referred to by others as distributable cash flow, is a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and is commonly used as a supplemental financial measure by management and by external users of financial statements such as investors, commercial banks, research analysts and rating agencies, to aid in assessing, among other things:

(1) the financial performance of our assets;

(2) our operating performance;

(3) the viability of potential projects, including our cash and overall return on alternative capital investments as compared to those of other companies in the midstream energy industry;

(4) the ability of our assets to generate cash sufficient to satisfy certain non-discretionary cash requirements, including interest payments and certain maintenance capital requirements; and

(5) our ability to make certain discretionary payments, such as distributions on our units, growth capital expenditures, certain maintenance capital expenditures and early payments of indebtedness.

We define Available Cash before Reserves (“Available Cash before Reserves”) as net income(loss) before interest, taxes, depreciation and amortization (including impairment, write-offs, accretion and similar items) after eliminating other non-cash revenues, expenses, gains, losses and charges (including any loss on asset dispositions), plus or minus certain other select items that we view as not indicative of our core operating results (collectively, “Select Items”), as adjusted for certain items, the most significant of which in the relevant reporting periods have been the sum of maintenance capital utilized, net interest expense and cash tax expense. Although, we do not necessarily consider all of our Select Items to be non-recurring, infrequent or unusual, we believe that an understanding of these Select Items is important to the evaluation of our core operating results. The most significant Select Items in the relevant reporting periods are set forth below.

| | Year Ended December 31, | |
|---|---|---|
| | 2018 | 2017 |
| I. Applicable to all Non-GAAP Measures | | |
| Differences in timing of cash receipts for certain contractual arrangements[1] | $(6,629 ) | $(17,540) |
| Adjustment regarding direct financing leases[2] | 7,633 | 6,921 |
| Certain non-cash items: | | |
| Unrealized (gain) loss on derivative transactions excluding fair value hedges, net of changes in inventory value | (10,455 ) | 9,942 |
| Loss on debt extinguishment | 3,339 | 6,242 |
| Adjustment regarding equity investees[3] | 28,088 | 31,852 |
| Other | 869 | 5,326 |
| Sub-total Select Items, net[4] | 22,845 | 42,743 |
| II. Applicable only to Available Cash before Reserves | | |
| Certain transaction costs[5] | 9,103 | 16,833 |
| Equity compensation adjustments | (207 ) | (1,227 ) |
| Other[6] | 16,208 | 946 |
| Total Select Items, net[7] | $47,949 | $59,295 |

(1) Represents the difference in timing of cash receipts from customers during the period and the revenue we recognize in accordance with GAAP on our related contracts. For purposes of our Non-GAAP measures, we add those amounts in the period of payment and deduct them in the period in which GAAP recognizes them.
(2) Represents the net effect of adding cash receipts from direct financing leases and deducting expenses relating to direct financing leases.
(3) Represents the net effect of adding distributions from equity investees and deducting earnings of equity investees net to us.
(4) Represents all Select Items applicable to Segment Margin.
(5) Represents transaction costs relating to certain merger, acquisition, transition and financing transactions incurred in advance of acquisition.
(6) Includes general and administrative costs associated with certain dispute costs during 2018.
(7) Represents Select Items applicable to Available Cash before Reserves.

Disclosure Format Relating to Maintenance Capital

We use a modified format relating to maintenance capital requirements because our maintenance capital expenditures vary materially in nature (discretionary vs. non-discretionary), timing and amount from time to time. We believe that, without such modified disclosure, such changes in our maintenance capital expenditures could be confusing and potentially misleading to users of our financial information, particularly in the context of the nature and purposes of our Available Cash before Reserves measure. Our modified disclosure format provides those users with information in the form of our maintenance capital utilized measure (which we deduct to arrive at Available Cash before Reserves). Our maintenance capital utilized measure constitutes a proxy for non-discretionary maintenance capital expenditures and it takes into consideration the relationship among maintenance capital expenditures, operating expenses and depreciation from period to period.

Maintenance Capital Requirements

MAINTENANCE CAPITAL EXPENDITURES

Maintenance capital expenditures are capitalized costs that are necessary to maintain the service capability of our existing assets, including the replacement of any system component or equipment which is worn out or obsolete. Maintenance capital expenditures can be discretionary or non-discretionary, depending on the facts and circumstances. Prior to 2014, substantially all of our maintenance capital expenditures have been (a) related to our pipeline assets and similar infrastructure, (b) non-discretionary in nature and (c) immaterial in amount as compared to our Available Cash before Reserves measure. Those historical expenditures were non-discretionary (or mandatory) in nature because we had very little (if any) discretion as to whether or when we incurred them. We had to incur them in order to continue to operate the related pipelines in a safe and reliable manner and consistently with past practices. If we had not made those expenditures, we would not have been able to continue to operate all or portions of those pipelines, which would not have been economically feasible. An example of a non-discretionary (or mandatory) maintenance capital expenditure would be replacing a segment of an old pipeline because one can no longer operate that pipeline safely, legally and/or economically in the absence of such replacement.

Table of Contents

Beginning with 2014, we believe a substantial amount of our maintenance capital expenditures from time to time will be (a) related to our assets other than pipelines, such as our marine vessels, trucks and similar assets, (b) discretionary in nature and (c) potentially material in amount as compared to our Available Cash before Reserves measure. Those expenditures will be discretionary (or non-mandatory) in nature because we will have significant discretion as to whether or when we incur them. We will not be forced to incur them in order to continue to operate the related assets in a safe and reliable manner. If we chose not make those expenditures, we would be able to continue to operate those assets economically, although in lieu of maintenance capital expenditures, we would incur increased operating expenses, including maintenance expenses. An example of a discretionary (or non-mandatory) maintenance capital expenditure would be replacing an older marine vessel with a new marine vessel with substantially similar specifications, even though one could continue to economically operate the older vessel in spite of its increasing maintenance and other operating expenses.

In summary, as we continue to expand certain non-pipeline portions of our business, we are experiencing changes in the nature (discretionary vs. non-discretionary), timing and amount of our maintenance capital expenditures that merit a more detailed review and analysis than was required historically. Management's increasing ability to determine if and when to incur certain maintenance capital expenditures is relevant to the manner in which we analyze aspects of our business relating to discretionary and non-discretionary expenditures. We believe it would be inappropriate to derive our Available Cash before Reserves measure by deducting discretionary maintenance capital expenditures, which we believe are similar in nature in this context to certain other discretionary expenditures, such as growth capital expenditures, distributions/dividends and equity buybacks. Unfortunately, not all maintenance capital expenditures are clearly discretionary or non-discretionary in nature. Therefore, we developed a measure, maintenance capital utilized, that we believe is more useful in the determination of Available Cash before Reserves.

MAINTENANCE CAPITAL UTILIZED

We believe our maintenance capital utilized measure is the most useful quarterly maintenance capital requirements measure to use to derive our Available Cash before Reserves measure. We define our maintenance capital utilized measure as that portion of the amount of previously incurred maintenance capital expenditures that we utilize during the relevant quarter, which would be equal to the sum of the maintenance capital expenditures we have incurred for each project/component in prior quarters allocated ratably over the useful lives of those projects/components.

Our maintenance capital utilized measure constitutes a proxy for non-discretionary maintenance capital expenditures and it takes into consideration the relationship among maintenance capital expenditures, operating expenses and depreciation from period to period. Because we did not use our maintenance capital utilized measure before 2014, our maintenance capital utilized calculations will reflect the utilization of solely those maintenance capital expenditures incurred since December 31, 2013.

Available Cash before Reserves for the years ended December 31, 2018 and 2017 was as follows:

| | Year Ended December 31, | |
|---|---|---|
| | 2018 | 2017 |
| | (in thousands) | |
| Net income (loss) attributable to Genesis Energy, L.P. | $(6,075) | $82,647 |
| Income Tax expense (benefit) | 1,498 | (3,959) |
| Depreciation, depletion, amortization, and accretion | 317,186 | 262,021 |
| Impairment expense | 126,282 | — |
| Plus (minus) Select Items, net | 47,949 | 59,295 |
| Maintenance capital utilized | (19,955) | (13,020) |
| Cash tax expense | (835) | (100) |
| Other | — | 2,148 |
| Available Cash before Reserves | $466,050 | $389,032 |

70

Table of Contents

## Liquidity and Capital Resources

### General

As of December 31, 2018, we believe our balance sheet and liquidity position remained strong, including $728.7 million of borrowing capacity available under our $1.7 billion senior secured revolving credit facility. We anticipate that our future internally-generated funds and the funds available under our credit facility will allow us to meet our ordinary course capital needs. Our primary sources of liquidity have been cash flows from operations, borrowing availability under our credit facility and the proceeds from issuances of equity and senior unsecured notes.

Our primary cash requirements consist of:

- working capital, primarily inventories and trade receivables and payables;
- routine operating expenses;
- capital growth and maintenance projects;
- acquisitions of assets or businesses;
- interest payments related to outstanding debt; and
- quarterly cash distributions to our unitholders.

### Capital Resources

Our ability to satisfy future capital needs will depend on our ability to raise substantial amounts of additional capital from time to time — including through equity and debt offerings (public and private), borrowings under our credit facility and other financing transactions—and to implement our growth strategy successfully. No assurance can be made that we will be able to raise necessary funds on satisfactory terms.

On October 11, 2018, we completed the sale of our Powder River Basin midstream assets, for which we received total net proceeds of approximately $300 million. We applied those net proceeds to reduce the balance outstanding under our revolving credit facility.

At December 31, 2018, we had $970.1 million borrowed under our credit facility, with $17.8 million of the borrowed amount designated as a loan under the inventory sublimit. Due to the revolving nature of loans under our credit facility, additional borrowings and periodic repayments and re-borrowings may be made until the maturity date of May 9, 2022. Our credit facility does not include a "borrowing base" limitation except with respect to our inventory loans.

The total amount available for borrowings under our credit facility at December 31, 2018 was $728.7 million.

At December 31, 2018, our long-term debt totaled $3.4 billion, consisting of $1.0 billion outstanding under our credit facility (including $17.8 million borrowed under the inventory sublimit tranche), $450 million of our 2026 Notes, $550 million of our 2025 Notes, $350 million of our 2024 Notes, $400 million of our 2023 Notes and $750 million of our 2022 Notes.

We have the right to redeem each of our series of notes beginning on specified dates as summarized below, at a premium to the face amount of such notes that varies based on the time remaining to maturity on such notes. Additionally, we may redeem up to 35% of the principal amount of each of our series of notes with the proceeds from an equity offering of our common units during certain periods. A summary of the applicable redemption periods is provided in the table below.

| | 2022 Notes | 2023 Notes | 2024 Notes | 2025 Notes | 2026 Notes |
|---|---|---|---|---|---|
| Redemption right beginning on | August 1, 2018 | May 15, 2018 | June 15, 2019 | October 1, 2020 | February 15, 2021 |
| Redemption of up to 35% of the principal amount of notes with the proceeds of an equity offering permitted prior to | August 1, 2018 | May 15, 2018 | June 15, 2019 | October 1, 2020 | February 15, 2021 |

For additional information on our long-term debt and covenants see Note 11 to our Consolidated Financial Statements in Item 8.

### Class A Convertible Preferred Units

On September 1, 2017, we sold $750 million of Class A convertible preferred units in a private placement, comprised of 22,249,494 units for a cash purchase price per unit of $33.71 (subject to certain adjustments, the “Issue Price”) to two initial purchasers. Our general partner executed an amendment to our partnership agreement in connection therewith, which, among other things, authorized and established the rights and preferences of our preferred units. Our preferred units are a new class of security that ranks senior to all of our currently outstanding classes or series of limited partner interests with respect to distribution and/or liquidation rights. Holders of our preferred units vote on an as-converted basis with holders of our common units and have certain class voting rights, including with respect to any amendment to the partnership agreement that would adversely affect the rights, preferences or privileges, or otherwise modify the terms, of those preferred units.

Each of our preferred units accumulate quarterly distribution amounts in arrears at an annual rate of 8.75% (or $2.9496), yielding a quarterly rate of 2.1875% (or $0.7374), subject to certain adjustments. With respect to any quarter ending on or prior to March 1, 2019, we have the option to pay to the holders of our preferred units the applicable distribution amount in cash, preferred units, or any combination thereof. If we elect to pay all or any portion of a quarterly distribution amount in preferred units, the number of such preferred units will equal the product of (i) the number of then outstanding preferred units and (ii) the quarterly rate. We have elected to pay all distribution amounts attributable to 2017 and 2018 in preferred units. For each period ending after March 1, 2019, we must pay all distribution amounts in respect of our preferred units in cash.

See Note 12 for additional information regarding our preferred units.

Equity Distribution Program and Shelf Registration Statements

We expect to issue additional equity and debt securities in the future to assist us in meeting our future liquidity requirements, particularly those related to opportunistically acquiring assets and businesses and constructing new facilities and refinancing outstanding debt.

In 2016, we implemented an equity distribution program that will allow us to consummate “at the market” offerings of common units from time to time through brokered transactions, which should help mitigate certain adverse consequences of underwritten offerings, including the downward pressure on the market price of our common units and the expensive fees and other costs associated with such public offerings. We entered into an equity distribution agreement with a group of banks who will act as sales agents or principals for up to $400.0 million of our common units, if and when we should elect to issue additional common units from time to time, although there are limits to the amount of our “at the market” offerings the market can absorb from time to time. In connection with implementing our equity distribution program, we filed a universal shelf registration statement (our "EDP Shelf") with the SEC. Our EDP Shelf allows us to issue up to $1.0 billion of equity and debt securities, whether pursuant to our equity distribution program or otherwise. Our EDP Shelf will expire in October 2020. As of December 31, 2018, we had issued no units under this program.

We have another universal shelf registration statement (our "2018 Shelf") on file with the SEC. Our 2018 Shelf allows us to issue an unlimited amount of equity and debt securities in connection with certain types of public offerings. However, the receptiveness of the capital markets to an offering of equity and/or debt securities cannot be assured and may be negatively impacted by, among other things, our long-term business prospects and other factors beyond our control, including market conditions. Our 2018 Shelf will expire in April 2021. We expect to file a replacement universal shelf registration statement before our 2018 Shelf expires.

Cash Flows from Operations

We generally utilize the cash flows we generate from our operations to fund our distributions and working capital needs. Excess funds that are generated are used to repay borrowings under our credit facility and/or to fund a portion of our capital expenditures. Our operating cash flows can be impacted by changes in items of working capital, primarily variances in the carrying amount of inventory and the timing of payment of accounts payable and accrued liabilities related to capital expenditures.

We typically sell our crude oil in the same month in which we purchase it, so we do not need to rely on borrowings under our credit facility to pay for such crude oil purchases, other than inventory. During such periods, our accounts receivable and accounts payable generally move in tandem as we make payments and receive payments for the purchase and sale of crude oil.

In our petroleum products activities, we buy products and typically either move those products to one of our storage facilities for further blending or sell those products within days of our purchase. The cash requirements for these activities can result in short term increases and decreases in our borrowings under our credit facility.

In our Alkali Business, we typically extract trona from our mining facilities, process into soda ash and other alkali products, and deliver and sell to our customers all within a relatively short time frame. If we did experience any differences in timing of extraction, processing and sales of this trona or Alkali products, this could impact the cash requirements for these activities in the short term.

The storage of our inventory of crude oil, petroleum products and alkali products can have a material impact on our cash flows from operating activities. In the month we pay for the stored crude oil or petroleum products (or pay for extraction and processing activities in the case of alkali products), we borrow under our credit facility (or use cash on hand) to pay for the

Table of Contents

crude oil or petroleum products (or extraction/processing of alkali products), utilizing a portion of our operating cash flows. Conversely, cash flow from operating activities increases during the period in which we collect the cash from the sale of the stored crude oil, petroleum products or alkali products. Additionally, we may be required to deposit margin funds with the NYMEX when commodity prices increase as the value of the derivatives utilized to hedge the price risk in our inventory fluctuates. These deposits also impact our operating cash flows as we borrow under our credit facility or use cash on hand to fund the deposits.

Net cash flows provided by our operating activities were $390.0 million and $323.6 million for 2018 and 2017, respectively. As discussed above, changes in the cash requirements related to payment for petroleum products or collection of receivables from the sale of inventory impact the cash provided by operating activities. Additionally, changes in the market prices for crude oil, petroleum products and alkali products can result in fluctuations in our working capital and, therefore, our operating cash flows between periods as the cost to acquire a barrel of crude oil or petroleum products (or the cost to extract/process in the case alkali products) will require more or less cash. The increase in operating cash flow for 2018 compared to 2017 was primarily due an increase in segment margin of $118.2 million partially offset by an increase in working capital of $12.3 million.

Net cash flows provided by our operating activities were $323.6 million and $282.8 million for 2017 and 2016, respectively. The increase in operating cash flow for 2017 compared to 2016 was primarily due to a decrease in working capital.

Capital Expenditures and Distributions Paid to Our Unitholders

We use cash primarily for our operating expenses, working capital needs, debt service, acquisition activities, internal growth projects and distributions we pay to our unitholders. We finance maintenance capital expenditures and smaller internal growth projects and distributions primarily with cash generated by our operations. We have historically funded material growth capital projects (including acquisitions and internal growth projects) with borrowings under our credit facility, equity issuances and/or the issuance of senior unsecured notes.

Table of Contents

Capital Expenditures and Business and Asset Acquisitions

The following table summarizes our expenditures for fixed assets, business and other asset acquisitions in the periods indicated:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| | | (in thousands) | |
| Capital expenditures for fixed and intangible assets: | | | |
| Maintenance capital expenditures: | | | |
| Offshore pipeline transportation assets | $4,202 | $ 5,037 | $3,530 |
| Sodium mineral and sulfur services assets | 55,377 | 24,045 | 2,274 |
| Marine transportation assets | 18,308 | 27,295 | 14,007 |
| Onshore facilities and transportation assets | 3,340 | 5,381 | 10,563 |
| Information technology systems | 72 | 286 | 547 |
| Total maintenance capital expenditures | 81,299 | 62,044 | 30,921 |
| Growth capital expenditures: | | | |
| Offshore pipeline transportation assets | $501 | $ 3,778 | $7,657 |
| Sodium minerals and sulfur services assets | 19,335 | 5,424 | — |
| Marine transportation assets | 12,560 | 41,119 | 64,797 |
| Onshore facilities and transportation assets | 47,770 | 143,742 | 306,075 |
| Information technology systems | 2,704 | 266 | 7,056 |
| Total growth capital expenditures | 82,870 | 194,329 | 385,585 |
| Total capital expenditures for fixed and intangible assets | 164,169 | 256,373 | 416,506 |
| Capital expenditures for business combinations, net of liabilities assumed: | | | |
| Acquisition of Alkali Business | $— | $ 1,325,000 | $— |
| Acquisition of remaining interest in equity investment | — | — | 35,090 |
| Total business combinations capital expenditures | — | 1,325,000 | 35,090 |
| Capital expenditures related to equity investees | 3,018 | — | — |
| Total capital expenditures | $167,187 | $ 1,581,373 | $451,596 |

Expenditures for capital assets to grow the partnership distribution will depend on our access to debt and equity capital. We will look for opportunities to acquire assets from other parties that meet our criteria for stable cash flows. We continue to pursue a long term growth strategy that may require significant capital.

Growth Capital Expenditures

All of our previously announced growth capital projects were placed in service prior to December 31, 2018. We are currently not anticipating growth capital expenditures during 2019 to exceed $50 million.

Maintenance Capital Expenditures

Maintenance capital expenditures increased during 2018 primarily due to the maintenance capital expenditures incurred related to our Alkali Business given the nature of its operations. We also incur maintenance capital expenditures in our marine transportation segment due to the costs to replace and upgrade certain equipment associated with our vessels. We expect future expenditures to be within a reasonable range of 2018's expenditures dependent upon the timing of when we incur certain costs. See previous discussion under "Available Cash before Reserves" for how such maintenance capital utilization is reflected in our calculation of Available Cash before Reserves.

Distributions to Unitholders

Our partnership agreement requires us to distribute 100% of our available cash (as defined therein) within 45 days after the end of each quarter to unitholders of record. Available cash generally means, for each fiscal quarter, all cash on hand at the end of the quarter:

Table of Contents

- less the amount of cash reserves that our general partner determines in its reasonable discretion is necessary or appropriate to:
- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments, or other agreements; or
- provide funds for distributions to our unitholders for any one or more of the next four quarters;

- plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings. Working capital borrowings are generally borrowings that are made under our credit facility and in all cases are used solely for working capital purposes or to pay distributions to partners.

On February 14, 2019, we paid a distribution of $0.55 per unit related to the fourth quarter of 2018. With respect to our Class A Convertible Preferred Units, we have declared a payment-in-kind ("PIK") of the quarterly distribution, which resulted in the issuance of an additional 534,576 Class A Convertible Preferred Units. This PIK amount equates to a distribution of $0.7374 per Class A Convertible Preferred Unit for the 2018 Quarter, or $2.9496 annualized. These distributions were paid on February 14, 2019 to unitholders holders of record at the close of business January 31, 2019.

Our historical distributions to common unitholders are shown in the table below (in thousands, except per unit amounts).

| Distribution For | Date Paid | | Per Unit Amount | Total Amount |
|---|---|---|---|---|
| 2016 | | | | |
| 4th Quarter | February 14, 2017 | | $0.7100 | $83,765 |
| 2017 | | | | |
| 1st Quarter | May 15, 2017 | | $0.7200 | $88,257 |
| 2nd Quarter | August 14, 2017 | | $0.7225 | $88,563 |
| 3rd Quarter | November 14, 2017 | | $0.5000 | $61,290 |
| 4th Quarter | February 14, 2018 | | $0.5100 | $62,515 |
| 2018 | | | | |
| 1st Quarter | May 15, 2018 | | $0.5200 | $63,741 |
| 2nd Quarter | August 14, 2018 | | $0.5300 | $64,967 |
| 3rd Quarter | November 14, 2018 | | $0.5400 | $66,193 |
| 4th Quarter | February 14, 2019 | (1) | $0.5500 | $67,419 |

(1) This distribution was paid on February 14, 2019 to unitholders of record as of January 31, 2019.

Table of Contents

Commitments and Off-Balance Sheet Arrangements

Contractual Obligations and Commercial Commitments

In addition to our credit facility discussed above, we have contractual obligations under operating leases as well as commitments to purchase crude oil and petroleum products. The table below summarizes our obligations and commitments at December 31, 2018.

| Commercial Cash Obligations and Commitments | Payments Due by Period Less than one year (in thousands) | 1 - 3 years | 3 - 5 Years | More than 5 years | Total |
|---|---|---|---|---|---|
| Contractual Obligations: | | | | | |
| Long-term debt [(1)] | $— | $— | $2,102,713 | $1,329,750 | $3,432,463 |
| Estimated interest payable on long-term debt [(2)] | 228,520 | 457,040 | 254,654 | 138,482 | 1,078,696 |
| Operating lease obligations | 46,042 | 70,029 | 55,087 | 126,229 | 297,387 |
| Unconditional purchase obligations [(3)] | 115,264 | 8,100 | 8,100 | 12,150 | 143,614 |
| Asset retirement obligations [(4)] | 67,544 | 31,139 | — | 141,182 | 239,865 |
| Total | $457,370 | $566,308 | $2,420,554 | $1,747,793 | $5,192,025 |

(1) Our credit facility allows us to repay and re-borrow funds at any time through the maturity date of May 9, 2022. We have $750 million in aggregate principal amount of senior unsecured notes that mature on August 1, 2022 (the "2022 Notes"), $400 million in aggregate principal amount of senior unsecured notes that mature on May 15, 2023 (the "2023 Notes"), $350 million in aggregate principal amount of senior unsecured notes that mature on June 15, 2024 (the "2024 Notes"), $550 million in aggregate principal amount of senior unsecured notes that mature on October 1, 2025 (the"2025 Notes"), and $450 million in aggregate principal amount of senior unsecured notes that mature on May 15, 2026 (the "2026 Notes").

(2) Interest on our long-term debt under our credit facility is at market-based rates. The interest rates on our 2022, 2023, 2024, 2025, and 2026 Notes are 6.75%. 6.00%, 5.625%, 6.50%, and 6.25%, respectively. The amount shown for interest payments represents the amount that would be paid if the debt outstanding at December 31, 2018 under our credit facility remained outstanding through the final maturity date of May 9, 2022 and interest rates remained at the December 31, 2018 market levels through the final maturity date. Also included is the interest on our senior unsecured notes through their respective maturity dates.

(3) Unconditional purchase obligations include agreements to purchase goods and services that are enforceable and legally binding and specify all significant terms. Contracts to purchase crude oil, petroleum products, and other chemicals and utilities are generally at market-based prices. For purposes of this table, estimated volumes and market prices at December 31, 2018 were used to value those obligations. The actual physical volumes and settlement prices may vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, changes in market prices and other conditions beyond our control.

(4) Represents the estimated future asset retirement obligations on a discounted basis. The recorded asset retirement obligation on our balance sheet at December 31, 2018 was $239.9 million and is further discussed in Note 7 to our Consolidated Financial Statements.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements, special purpose entities, or financing partnerships, other than as disclosed under “Contractual Obligations and Commercial Commitments” above.

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. We base these estimates and assumptions on historical experience and other information that are believed to be reasonable under the circumstances. Estimates and assumptions about future events and their effects cannot be determined with certainty, and, accordingly, these estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as the business environment in which we operate changes. Significant accounting policies that we employ are presented in the Notes to our Consolidated Financial Statements in Item 8 (see Note 2 “Summary of Significant Accounting Policies”).

We have defined critical accounting policies and estimates as those that are most important to the portrayal of our financial results and positions. These policies require management’s judgment and often employ the use of information that is inherently uncertain. Our most critical accounting policies pertain to measurement of the fair value of assets and liabilities in business acquisitions, depreciation, amortization and impairment of long-lived assets, deferred maintenance on marine fixed assets, equity plan compensation accruals and contingent and environmental liabilities. We discuss these policies below.

Fair Value of Assets and Liabilities Acquired and Identification of Associated Goodwill and Intangible Assets

In conjunction with each acquisition we make, we must allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. As additional information becomes available, we may adjust the original estimates within a short time period subsequent to the acquisition. In addition, we are required to recognize intangible assets separately from goodwill. Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as customer relationships, contracts, trade names and non-compete agreements involves professional judgment and is ultimately based on acquisition models and management’s assessment of the value of the assets acquired, and to the extent available, third party assessments. Intangible assets with finite lives are amortized over their estimated useful life as determined by management. Goodwill is not amortized but instead is periodically assessed for impairment. Uncertainties associated with these estimates include fluctuations in economic obsolescence factors in the area and potential future sources of cash flow. We cannot provide assurance that actual amounts will not vary significantly from estimated amounts. See Note 4 to our Consolidated Financial Statements in Item 8 regarding further discussion regarding our acquisitions.

Depreciation, Amortization and Depletion of Long-Lived Assets and Intangibles

In order to calculate depreciation, depletion and amortization we must estimate the useful lives of our fixed assets (including the reserve life of our mineral leaseholds) at the time the assets are placed in service. We compute depreciation using the straight-line method based on these estimated useful lives. The actual period over which we will use the asset may differ from the assumptions we have made about the estimated useful life. We adjust the remaining useful life as we become aware of such circumstances.

Intangible assets with finite useful lives are required to be amortized over their respective estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset shall be amortized over the best estimate of its useful life. At a minimum, we will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required. We are recording amortization of our customer and supplier relationships, licensing agreements, trade names, non-compete agreements, and other contract intangibles based on the period over which the asset is expected to contribute to our future cash flows. Generally, the contribution of these assets to our cash flows is expected to decline over time, such that greater value is attributable to the periods shortly after the acquisition was made. Our favorable lease and other intangible assets are being amortized on a straight-line basis over their expected useful lives.

We compute depletion using the units of production method using actual production and our estimated reserve life. The actual reserve life may differ from the assumptions we have made about the estimated reserve life.

Impairment of Long-Lived Assets including Intangibles and Goodwill

When events or changes in circumstances indicate that the carrying amount of a fixed asset or intangible asset with finite lives may not be recoverable, we review our assets for impairment. We compare the carrying value of the fixed asset to the estimated undiscounted future cash flows expected to be generated from that asset. Estimates of future net cash flows include estimating future volumes, future margins or tariff rates, future operating costs and other estimates and assumptions consistent with our business plans. If we determine that an asset’s unamortized cost may not be recoverable due to impairment; we may be required to reduce the carrying value and the subsequent useful life of the asset. During 2018, we recognized impairment expense of $103.2 million associated with long-lived assets (refer to Note 7 for additional details).

Any such write-down of the value and unfavorable change in the useful life of an intangible asset would increase costs and expenses at that time. Goodwill represents the excess of the purchase prices we paid for certain businesses over their respective fair values. We do not amortize goodwill; however, we evaluate, and test if necessary, our goodwill (at the reporting unit level) for impairment on October 1 of each fiscal year, and more frequently, if indicators of impairment are present.

We may perform a qualitative assessment of relevant events and circumstances about the likelihood of goodwill impairment. If it is deemed more likely than not the fair value of the reporting unit is less than its carrying amount, we calculate the fair value of the reporting unit. Otherwise, further testing is not required. We may also elect to exercise our unconditional option to bypass this qualitative assessment, in which case we would also calculate the fair value of the reporting unit. The qualitative assessment is based on reviewing the totality of several factors, including macroeconomic conditions, industry and market considerations, cost factors, overall financial performance, other entity specific events (for example, changes in management) or other events such as selling or disposing of a reporting unit. The determination of a reporting unit's fair value is predicated on our assumptions regarding the future economic prospects of the reporting unit. Such assumptions include

(i) discrete financial forecasts for the assets contained within the reporting unit, which rely on management's estimates of operating margins, (ii) long-term growth rates for cash flows beyond the discrete forecast period, (iii) appropriate discount rates and (iv) estimates of the cash flow multiples to apply in estimating the market value of our reporting units. If the fair value of the reporting unit (including its inherent goodwill) is less than its carrying value, a charge to earnings may be required to reduce the carrying value of goodwill to its implied fair value. If future results are not consistent with our estimates, we could be exposed to future impairment losses that could be material to our results of operations. We monitor the markets for our products and services, in addition to the overall market, to determine if a triggering event occurs that would indicate that the fair value of a reporting unit is less than its carrying value.

We performed a quantitative assessment as of October 1, 2018, for both our refinery services and supply and logistics reporting units that have goodwill. No impairment was recorded in our refinery services segment during 2018 as the fair value far exceeded the carrying value. Our supply and logistics reporting unit, which primarily includes our legacy crude oil and refined products marketing and trucking businesses, was determined to have a fair value lower than its carrying value and the partnership recorded an impairment charge of $23.1 million during 2018 (Note 10).

One of our other monitoring procedures is the comparison of our market capitalization to our book equity on a quarterly basis to determine if there is an indicator of impairment. As of December 31, 2018, our market capitalization exceeded the book value of our equity (partner's capital) and there were no other indicators of impairment identified. For additional information regarding our goodwill, see Note 10 to our Consolidated Financial Statements in Item 8.

Equity Compensation Plan Accrual

Our 2010 Long-Term Incentive Plan provides for grantees, which may include key employees and directors, to receive cash at the vesting of the phantom units equal to the average of the closing market price of our common units for the twenty trading days prior to the vesting date. Our phantom units under this plan are comprised of both service-based and performance-based awards. Until the vesting date, we calculate estimates of the fair value of the awards and record that value as compensation expense during the vesting period on a straight-line basis. These estimates are based on the current trading price of our common units and an estimate of the forfeiture rate we expect may occur. For our performance-based awards, our fair value estimates are weighted based on probabilities for each performance condition applicable to the award. At December 31, 2018, we had 573,945 phantom units outstanding and recorded expense of $2.1 million during 2018. The liability recorded for phantom units expected to vest fluctuates with the market price of our common units. At the date of vesting, any difference between the estimates recorded and the actual cash paid to the grantee will be charged to expense. At December 31, 2018, we estimated approximately $0.6 million of remaining compensation costs to be recognized over a weighted average period of approximately 9 months. Changes in our assumptions may impact our liabilities and expenses related to these awards.

See Note 17 to our Consolidated Financial Statements in Item 8 for further discussion regarding our equity compensation plans.

Fair Value of Derivatives

The fair value of a derivative at a particular period end does not reflect the end results of a particular transaction, and will most likely not reflect the gain or loss at the conclusion of a transaction. We reflect estimates for these items based on our internal records and information from third parties. We have commodity and other derivatives that are accounted for as assets and liabilities at fair value in our Consolidated Balance Sheets. The valuations of our derivatives that are exchange traded are based on market prices on the applicable exchange on the last day of the period. For our derivatives that are not exchange traded, the estimates we use are based on indicative broker quotations or an internal valuation model. Our valuation models utilize market observable inputs such as price, volatility, correlation and other factors and may not be reflective of the price at which they can be settled due to the lack of a liquid market.

We also have embedded derivatives in our Class A Convertible preferred units that are accounted for as liabilities at fair value in our Consolidated Balance Sheet as of December 31, 2018. Derivatives related to the embedded derivatives in our preferred units are valued using a model that contains inputs, including our common unit price, 30-year U.S. Treasury rates, default probabilities and timing estimates, which involve management judgment.

Liability and Contingency Accruals

We accrue reserves for contingent liabilities including environmental remediation and potential legal claims. When our assessment indicates that it is probable that a liability has occurred and the amount of the liability can be reasonably estimated, we make accruals. We base our estimates on all known facts at the time and our assessment of the ultimate outcome, including consultation with external experts and counsel. We revise these estimates as additional information is obtained or resolution is achieved.

Table of Contents

We also make estimates related to future payments for environmental costs to remediate existing conditions attributable to past operations. Environmental costs include costs for studies and testing as well as remediation and restoration. We sometimes make these estimates with the assistance of third parties involved in monitoring the remediation effort.
At December 31, 2018, we were not aware of any contingencies or liabilities that would have a material effect on our financial position, results of operations or cash flows.
Recent Accounting Pronouncements
Recently Issued and Recently Adopted
We have adopted guidance under ASC Topic 606, Revenue from Contracts with Customers, and all related ASUs (collectively "ASC 606") as of January 1, 2018 utilizing the modified retrospective method of adoption. The adoption date for our material equity method investment in the Poseidon Oil Pipeline Company, LLC will follow the non-public business entity adoption date of January 1, 2019 for its stand-alone financial statements. Refer to Note 3 for further details.
In July 2015, the FASB issued guidance modifying the accounting for inventory. Under this guidance, the measurement principle for inventory will change from lower of cost or market value to lower of cost and net realizable value. The guidance defines net realizable value as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The guidance is effective for reporting periods after December 15, 2016, with early adoption permitted. We have adopted this guidance as of January 1, 2017 with no material impact on our consolidated financial statements.
In February 2016, the FASB issued guidance to improve the transparency and comparability among companies by requiring lessees to recognize a lease liability and a corresponding lease asset for virtually all lease contracts. The guidance also requires additional disclosure about leasing arrangements. The guidance is effective for interim and annual periods beginning after December 15, 2018 and requires a modified retrospective approach to adoption.
In preparation for adoption of the new lease standard, we have reviewed the practical expedients that are available to facilitate the adoption process. We plan to elect to take the "package" of practical expedients set out in the standard, which must be elected together. The items within the package stipulate that an entity need not reassess: (1) if expired or existing contracts contain leases, (2) lease classification for previously-assessed leases under ASC 840, and (3) initial direct costs for existing leases. We will also elect to adopt the practical expedient relating to the separation of lease and non-lease components as well as the easement and right of way expedient. Finally we will elect to utilize the optional transition method which allows the company to only apply the new lease standard at the date of adoption while comparative periods will be presented under the previous lease guidance. We will not adopt the hindsight practical expedient.
As a result of adopting the new lease standard, we expect an impact on our consolidated balance sheet from the recognition of a right-of-use asset and the corresponding lease liability of less than $250 million. We do not expect a material impact to partners capital as a result of our transition adjustment.
In August 2016, the FASB issued guidance that addresses how certain cash receipts and payments are presented and classified in the statement of cash flows under Topic 230, Statement of Cash flow, and other Topics. The guidance is effective for annual reporting periods, and interim periods therein, beginning after December 15, 2017. We have adopted this guidance as of January 1, 2018 using the retrospective transition method to each period presented on the Consolidated Statements of Cash Flows. We reclassified $15.3 million and $15.6 million from operating cash flows to investing cash flows for the years ended December 31, 2017 and 2016, respectively.
In March 2017, the FASB issued ASU 2017-07, Compensation-Retirement Benefits (Topic 715). ASU 2017-07 requires employers to separate the service cost component from the other components of net benefit cost in the period. The new standard requires the other components of net benefit costs (excluding service costs), be reclassified to "Other expense" from "General and administrative." We adopted this standard as of January 1, 2018. This standard is applied retrospectively. The effect was not material to our financial statements for the year ended December 31, 2018.
In January 2017, the FASB issued guidance to simplify the goodwill impairment testing at annual or interim periods. The guidance eliminates Step 2 from the goodwill impairment testing process, and any identified impairment charge would be simplified to be the difference between the carrying value and fair value of a reporting unit, but would not

exceed the total amount of goodwill allocated to the reporting unit in question. The guidance is effective for annual reporting periods, and interim periods therein, beginning after December 15, 2019. We elected to early adopt this standard as of January 1, 2017. See Note 10 for further information.

Table of Contents

Item 7a. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to various market risks, primarily related to volatility in crude oil and petroleum products prices, soda ash prices, NaHS and NaOH prices, natural gas prices and interest rates. Our policy is to purchase only commodity products for which we have a market, and to structure our sales and purchase contracts so that price fluctuations for those products do not materially affect the Segment Margin we receive. We do not acquire and hold futures contracts or other derivative products for the purpose of speculating on price changes.

Our primary price risk relates to the effect of crude oil and petroleum products price fluctuations on our inventories and the fluctuations each month in grade and location differentials and their effect on future contractual commitments. Our risk management policies are designed to monitor our physical volumes, grades and delivery schedules to ensure our hedging activities address the market risks that are inherent in our gathering and marketing activities.

We utilize NYMEX commodity based futures contracts and option contracts to hedge our exposure to these market price fluctuations as needed. All of our open commodity price risk derivatives at December 31, 2018 were categorized as non-trading. On December 31, 2018 we had entered into NYMEX future contracts that will settle between January and April 2019 and NYMEX options contracts that will settle during January and March 2019.

Our Alkali Business relies on natural gas to generate heat and power for operations. We use a combination of commodity price swap contracts and future purchase contracts to manage our exposure to fluctuations in natural gas prices. The swap contracts fix the basis differential between NYMEX Henry Hub and NW Rocky Mountain posted prices. As of December 31, 2018 we had entered into NYMEX future contracts and over the counter swap contracts that will settle between January and December 2019.

This accounting treatment is discussed further in Note 19 to our Consolidated Financial Statements. We believe our hedging activities have been successful in helping to mitigate these risks.

The table below presents information about our open commodity derivative contracts at December 31, 2018. Notional amounts in barrels or gallons, the weighted average contract price, total contract amount and total fair value amount in U.S. dollars of our open positions are presented below. Fair values were determined by using the notional amount in barrels or gallons multiplied by the December 31, 2018 quoted market prices. All of the hedge positions offset physical exposures to the cash market; none of these offsetting physical exposures are included in the table below.

| | Unit of Measure for Volume | Contract Volumes (in 000's) | Unit of Measure for Price | Weighed Average Market Price | Contract Value (in 000's) | Mark-to Market Change (in 000's) | Settlement Value (in 000's) |
|---|---|---|---|---|---|---|---|
| Futures and Swap Contracts | | | | | | | |
| Sell (Short) Contracts: | | | | | | | |
| Crude Oil | Bbl | 349 | Bbl | $ 51.48 | $ 17,578 | $ (1,304) | $ 16,274 |
| Natural Gas Swaps | MMBTU | 502 | MMBTU | $ 0.62 | $ 3,120 | $ (1,149) | $ 1,971 |
| Diesel | Bbl | 2 | Gal | $ 1.89 | $ 159 | $ (17) | $ 142 |
| #6 Fuel Oil | Bbl | 382 | Bbl | $ 51.41 | $ 19,639 | $ (1,631) | $ 18,008 |
| Natural Gas | MMBTU | 137 | MMBTU | $ 2.91 | $ 4,839 | $ (166) | $ 4,673 |
| RBOB Gas | Bbl | 2 | Gal | $ 1.35 | $ 113 | $ (4) | $ 109 |
| Buy (Long) Contracts: | | | | | | | |
| Crude Oil | Bbl | 234 | Bbl | $ 49.37 | $ 11,553 | $ (522) | $ 11,031 |
| Diesel | Bbl | 2 | Gal | $ 1.85 | $ 155 | $ (14) | $ 141 |
| #6 Fuel Oil | Bbl | 40 | Bbl | $ 49.94 | $ 1,998 | $ (123) | $ 1,875 |
| Natural Gas | MMBTU | 590 | MMBTU | 2.92 | 17,169 | 81 | $ 17,250 |
| RBOB Gas | Bbl | 1 | Gal | 1.29 | 54 | 1 | $ 55 |

Option Contracts

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Written Contracts: | | | | | | | |
| Crude Oil | Bbl | 26 | Bbl | $ 2.66 | $ 69 | $ (21 ) | $ 48 |

We manage our risks of volatility in NaOH prices by indexing prices for the sale of NaHS to the market price for NaOH in most of our contracts. Given the competitive advantages associated with our naturally produced soda ash as previously discussed (relative to that which is synthetically produced), we believe this somewhat mitigates market risk within our Alkali Business.

We are also exposed to market risks due to the floating interest rates on our credit facility. Obligations under our senior secured credit facility bear interest at the LIBOR rate or alternate base rate (which approximates the prime rate), at our option, plus the applicable margin. We have not historically hedged our interest rates. On December 31, 2018, we had $1.0 billion of debt outstanding under our credit facility. For the year ended December 31, 2018, a 10% change in LIBOR would have resulted in approximately a $5.9 million change in net income.

The Preferred Distribution Rate Reset Election of our Class A convertible preferred units is an embedded derivative that must be bifurcated from the related host contract, the preferred unit purchase agreement, and recorded at fair value in our Consolidated Balance Sheets. The valuation model utilized for this embedded derivative contains inputs including our common unit price, U.S. treasury rates and dividend yields to ultimately calculate the fair value of our Class A convertible preferred units with and without the Preferred Distribution Rate Reset Option. See Note 12 to our Consolidated Financial Statements for a discussion of embedded derivatives.

## Item 8. Financial Statements and Supplementary Data

The information required hereunder is included in this report as set forth in the “Index to Consolidated Financial Statements.”

## Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

## Item 9A. Controls and Procedures

### Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures and internal controls designed to ensure that information required to be disclosed in our filings under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission’s rules and forms. Our chief executive officer and chief financial officer, with the participation of our management, have evaluated our disclosure controls and procedures as of the end of the period covered by this Annual Report on Form 10-K and have determined that such disclosure controls and procedures are effective in providing assurance of the timely recording, processing, summarizing and reporting of information, and in accumulation and communication to management on a timely basis material information relating to us (including our consolidated subsidiaries) required to be disclosed in this Annual Report on Form 10-K.

### Changes in Internal Controls over Financial Reporting

There were no changes during our last fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

### Management’s Report on Internal Control over Financial Reporting

Management of the Partnership is responsible for establishing and maintaining effective internal control over financial reporting as defined in Rules 13a-15(f) under the Securities Exchange Act of 1934. The Partnership’s internal control over financial reporting is designed to provide reasonable assurance to the Partnership’s management and board of directors regarding the preparation and fair presentation of published financial statements.

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

Management assessed the effectiveness of the Partnership’s internal control over financial reporting as of December 31, 2018. In making this assessment, management used the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on our assessment, we believe that, as of December 31, 2018, the Partnership’s internal control over financial reporting is effective based on those criteria.

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, our management included a report of their assessment of the design and effectiveness of our internal controls over financial reporting as part of this Annual Report on Form 10-K for the fiscal year ended December 31, 2018. Ernst & Young LLP, the Partnership’s independent registered public accounting firm,

Table of Contents

has issued an attestation report on the effectiveness of the Partnership’s internal control over financial reporting. Ernst & Young’s attestation report on the Partnership’s internal control over financial reporting appears in Item 8. “Financial Statements and Supplementary Data.”

Table of Contents

Item 9B. Other Information
None.
Part III
Item 10. Directors, Executive Officers and Corporate Governance
Management of Genesis Energy, L.P.
We are a Delaware limited partnership. We conduct our operations and own our operating assets through our subsidiaries and joint ventures. Our general partner, Genesis Energy, LLC, a wholly-owned subsidiary that owns a non-economic general partner interest in us, has sole responsibility for conducting our business and managing our operations. It also employs most of our personnel, including executive officers. Employees of our Alkali operations are employed by Genesis Alkali, LLC, a wholly-owned subsidiary.

The board of directors of our general partner (which we refer to as “our board of directors”) must approve significant matters (such as material business strategies, mergers, business combinations, acquisitions or dispositions of assets, issuances of common units, incurrences of debt or other financings and the payments of distributions). The holders of our Class B Common Units are entitled to (i) vote in the election of our board of directors, subject to the Davison family’s rights under its unitholder rights agreement (described below), as well as (ii) vote on substantially all other matters on which our Class A holders are entitled to vote. The holders of our Class A Common Units are not entitled to vote in the election of directors, but they are entitled to vote in a very limited number of other circumstances, including our merger with another company. As is common with MLPs, our partnership structure does not grant our unitholders (in such capacity) the right to directly or indirectly participate in our management or operations other than through the exercise of their limited voting rights.

Collectively, members of the Davison family own approximately 10.3% of our Class A Common Units and 77.0% of our Class B Common Units, for a combined ownership percentage of 10.2% of total Common Units. Pursuant to its unitholder rights agreement, the Davison family is entitled to elect up to three of our directors based on its members’ collective ownership percentage of our outstanding common units: (i) with 15% or more ownership, they have the right to appoint three directors, (ii) with less than 15% ownership but more than 10%, they have the right to appoint two directors, and (iii) with less than 10% ownership, they have the right to appoint one director. That unitholder rights agreement also provides that, so long as the Davison family has the right to elect three directors thereunder, our board of directors cannot have more than 11 directors without the Davison family’s consent. In addition to their rights under that unitholder rights agreement, if the members of the Davison family act as a group, they have the ability to elect at least a majority of our directors because they own a majority of our Class B units.
Under our limited partnership agreement, the organizational documents of our general partner and indemnification agreements with our directors, subject to specified limitations, we will indemnify to the fullest extent permitted by Delaware law, from and against all losses, claims, damages or similar events, any director or officer, or while serving as director or officer, any person who is or was serving as a tax matters member or as a director, officer, tax matters member, employee, partner, manager, fiduciary or trustee of our partnership or any of our affiliates. Additionally, we will indemnify to the fullest extent permitted by law, from and against all losses, claims, damages or similar events, any person who is or was an employee (other than an officer) or agent of our general partner.
Our board of directors currently consists of Sharilyn S. Gasaway, James E. Davison, James E. Davison, Jr., Kenneth M. Jastrow II, Conrad P. Albert, Jack T. Taylor and Mr. Sims. Our board of directors has determined that each of Ms. Gasaway and Messrs. Jastrow, Albert and Taylor is an independent director under the NYSE rules.
Board Leadership Structure and Risk Oversight
Board Leadership Structure
Our board of directors has no policy that requires the positions of the Chairman of the Board and the Chief Executive Officer to be held by the same or different persons or that we designate a lead or presiding independent director. Our board of directors believes it is important to retain the flexibility to make those determinations based on an assessment of the circumstances existing from time to time, including the composition, skills and experience of our board of directors and its members, specific challenges faced by the company or the industry in which it operates, and

governance efficiency.

Presently, our board of directors believes that, because Mr. Sims is the director most familiar with our business and industry and the most capable of leading the discussion of, and executing on, our business strategy, he is best situated to serve as Chairman, regardless of the fact that he is the Chief Executive Officer of our general partner. Our board of directors also believes that the appointment of a lead independent director, who will preside over executive sessions of non-management directors of our board of directors, will facilitate teamwork and communication between the non-management directors and management. Our board of directors appointed Mr. Jastrow as our lead independent director because of his executive experience and service as a director of other companies. Our board of directors believes that the combined role of Chairman and Chief Executive Officer working with the lead independent director is currently in the best interest of unitholders, providing the appropriate balance between developing our strategy and overseeing management.

On September 1, 2017, we sold $750 million of Class A convertible preferred units in a private placement, comprised of 22,249,494 units for a cash purchase price per unit of $33.71 (subject to certain adjustments, the "Issue Price") to two initial purchasers. In connection with the private placement, we have granted each initial purchaser (including its applicable affiliate transferees) certain rights, including (i) the right to appoint an observer, who shall have the right to attend our board meetings for so long as an initial purchaser (including its affiliates) owns at least $200 million of our preferred units and (ii) the right to appoint two directors to our general partner's board of directors if (and so long as) we fail to pay in full any three quarterly distribution amounts, whether or not consecutive, attributable to any period ending after March 1, 2019.

We are committed to sound principles of governance. Such principles are critical for us to achieve our performance goals and maintain the trust and confidence of investors, personnel, suppliers, business partners and stakeholders. We believe independent directors are a key element for strong governance, although we have reserved or exercised our right as a limited partnership under the listing standards of the NYSE not to comply with certain requirements of the NYSE. For example, although at least a majority of the members of our board of directors is independent under the NYSE rules, we reserve the right not to comply with Section 303A.01 of the NYSE Listed Company Manual in the future, which would require that our board of directors be comprised of at least a majority of independent directors. In addition, among other things, we have elected not to comply with Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which would require our board of directors to maintain a nominating/corporate governance committee and a compensation committee, each consisting entirely of independent directors. Our corporate governance guidelines are available on our website (www.genesisenergy.com) free of charge. For further discussion of director independence, please see Item 13. "Certain Relationships and Related Transactions, and Director Independence—Director Independence."

Risk Oversight

We face a number of risks, including exposure to matters relating to the environment, regulation, competition, fluctuations in commodity prices and interest rates and severe weather. Management is responsible for the day-to-day management of the risks our company faces, although our board of directors, as a whole and through its committees, has responsibility for the oversight of risk management. In fulfilling its risk oversight role, our board of directors must determine whether risk management processes designed and implemented by our management are adequate and functioning as designed. Senior management regularly delivers presentations to our board of directors on strategic matters, operations, risk management and other matters, and are available to address any questions or concerns raised by our board of directors. Board of directors meetings also regularly include discussions with senior management regarding strategies, key challenges and risks and opportunities for our company.

Our board committees assist our board of directors in fulfilling its oversight responsibilities in certain areas of risk. For example, the audit committee assists with risk management oversight in the areas of financial reporting, internal controls and compliance with legal and regulatory requirements and our risk management policy relating to our hedging program. The governance, compensation and business development committee assists our board of directors with risk management relating to our compensation policies and programs.

Our board of directors believes that it is important to align (when practical) the interests of the members of our board of directors and certain of our officers with the interests of our long-term stakeholders. Our board of directors has adopted certain policies to further promote that alignment of interests. For example, among other things, our policies prohibit our directors and officers from (i) buying, selling or engaging in transactions with respect to our common units while they are aware of material non-public information and (ii) engaging in short sales of our securities. Certain of our directors and/or officers own substantial amounts of our units, some of which are pledged, including being held in broker margin accounts. See Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters."

Audit Committee

The audit committee of our board of directors generally oversees our accounting policies and financial reporting and the audit of our financial statements. The audit committee assists our board of directors in its oversight of the quality and integrity of our financial statements and our compliance with legal and regulatory requirements. Our independent registered public accounting firm is given unrestricted access to the audit committee. Our board of directors has determined that the members of the audit committee meet the independence and experience standards established by NYSE and the Securities Exchange Act of 1934, as amended. In accordance with the NYSE rules and the Securities Exchange Act of 1934, as amended, our board of directors has named three of its members to serve on the audit committee—Sharilyn S. Gasaway, Conrad P. Albert and Jack T. Taylor. Ms. Gasaway is the chairperson. Our board of directors believes that Ms. Gasaway and Mr. Taylor qualify

Table of Contents

as audit committee financial experts as such term is used in the rules and regulations of the SEC. The charter of the audit committee is available on our website (www.genesisenergy.com) free of charge. Each member of the audit committee is an independent director under NYSE rules.

Governance, Compensation and Business Development Committee

The governance, compensation and business development committee, or G&C Committee, of our board of directors generally (i) monitors compliance with corporate governance guidelines, (ii) reviews and makes recommendations regarding board and committee composition, structure, size, compensation and related matters, and (iii) oversees compensation plans and compensation decisions for our employees. All the members of our board of directors, other than our CEO, serve as members of the G&C Committee. Mr. Jastrow is the chairperson. The charter of the G&C Committee is available on our website (www.genesisenergy.com) free of charge.

Conflicts Committee

To the extent requested by our board of directors, a conflicts committee of our board of directors would be appointed to review specific matters in connection with the resolution of conflicts of interest and potential conflicts of interest between any of our affiliates and us. If a specific review is requested by our board of directors, our conflicts committee would be formed by our Board and would be comprised solely of independent directors. See Item 13. "Certain Relationships and Related Transactions, and Director Independence—Review or Special Approval of Material Transactions with Related Persons."

Executive Sessions of Non-Management Directors

Our board of directors holds executive sessions in which non-management directors meet without any members of management present in connection with regular board meetings. The purpose of these executive sessions is to promote open and candid discussion among the non-management directors. Mr. Jastrow, as the lead independent director, serves as the presiding director at those executive sessions. In accordance with NYSE rules, interested parties can communicate directly with non-management directors by mail in care of the General Counsel and Secretary or in care of the chairperson of the audit committee at 919 Milam, Suite 2100, Houston, TX 77002. Such communications should specify the intended recipient or recipients. Commercial solicitations or communications will not be forwarded. We have established a toll-free, confidential telephone hotline so that interested parties may communicate with the chairperson of the audit committee or with all the non-management directors as a group. All calls to this hotline are reported to the chairperson of the audit committee who is responsible for communicating any necessary information to the other non-management directors. The number of our confidential hotline is (800) 826-6762.

Table of Contents

Directors and Executive Officers

Set forth below is certain information concerning our directors and executive officers, effective as of February 28, 2019.

| Name | Age | Position |
|---|---|---|
| Grant E. Sims | 63 | Director, Chairman of the Board, and Chief Executive Officer |
| Conrad P. Albert | 72 | Director |
| James E. Davison | 81 | Director |
| James E. Davison, Jr. | 52 | Director |
| Sharilyn S. Gasaway | 50 | Director |
| Kenneth M. Jastrow II | 71 | Director |
| Jack T. Taylor | 67 | Director |
| Robert V. Deere | 64 | Chief Financial Officer |
| Edward T. Flynn | 60 | Executive Vice President |
| Richard R. Alexander | 43 | Vice President |
| Karen N. Pape | 60 | Senior Vice President and Controller |
| Kristen O. Jesulaitis | 49 | General Counsel |
| William S. Goloway | 58 | Vice President |
| Garland G. Gaspard | 64 | Senior Vice President |
| Chad A. Landry | 55 | Vice President |
| Ryan S. Sims | 35 | Vice President |

Grant E. Sims has served as a director and Chief Executive Officer of our general partner since August 2006 and Chairman of the Board of our general partner since October 2012. Mr. Sims was affiliated with Leviathan Gas Pipeline Partners, LP from 1992 to 1999, serving as the Chief Executive Officer and a director beginning in 1993 until he left to pursue personal interests, including investments. Leviathan (subsequently known as El Paso Energy Partners, L.P. and then GulfTerra Energy Partners, L.P.) was a NYSE listed master limited partnership. Mr. Sims has an established track record of developing strong companies and has led his companies through a period of substantial growth while increasing geographic and operational diversity. Mr. Sims provides leadership skills, executive management experience and significant knowledge of our business environment, which he has gained through his vast experience with other MLPs.

Conrad P. Albert has served as a director of our general partner since July 2013. Mr. Albert is a private investor and was formerly a director of Anadarko Petroleum Corporation from 1986 to 2006. Mr. Albert also served as a director of DeepTech International, Inc. from 1992 to 1998. From 1969 to 1991, Mr. Albert served in various positions with Manufacturers Hanover Trust Company, ultimately serving as Executive Vice President in charge of worldwide energy lending and corporate finance. Mr. Albert's extensive financial, executive and directorial experience and his service in various roles in the management of other energy-related companies will allow him to provide valuable expertise to our board of directors.

James E. Davison has served as a director of our general partner since July 2007. Mr. Davison served as chairman of the board of Davison Transport, Inc. for over 30 years. He also serves as President of Terminal Services, Inc. Mr. Davison has over forty years of experience in the energy-related transportation and sulfur removal businesses. Mr. Davison brings to our board of directors significant energy-related transportation and sulfur removal experience and industry knowledge.

James E. Davison, Jr. has served as a director of our general partner since July 2007. Mr. Davison is also a director of another public company, Origin Bancorp, Inc., and serves on its finance and risk committees. Mr. Davison is the son of James E. Davison. Mr. Davison's executive and leadership experience enable him to make valuable contributions to our board of directors.

Sharilyn S. Gasaway has served as a director of our general partner since March 2010 and serves as chairperson of the audit committee. Ms. Gasaway is a private investor and was Executive Vice President and Chief Financial Officer of Alltel Corporation, a wireless communications company, from 2006 to 2009. She served as Controller of Alltel

Corporation from 2002 through 2006. Ms. Gasaway is a director of two other public companies, JB Hunt Transport Services, Inc. and Waddell and Reed Financial, Inc., serving on the audit committee of each company. Additionally, Ms. Gasaway serves on the compensation and nominating committees of JB Hunt and the nominating and corporate governance committee of Waddell and Reed. Ms. Gasaway provides our board of directors valuable management and financial expertise, including an understanding of the accounting and financial matters that we address on a regular basis.

Kenneth M. Jastrow II has served as a director of our general partner since March 2010 and serves as our lead independent director and the chairperson of the G&C Committee. Mr. Jastrow served as Chairman and Chief Executive Officer of Temple-Inland, Inc., a manufacturing company and the former parent of Forestar Group, from 2000 to 2007. Prior to that, Mr. Jastrow served in various roles at Temple-Inland, including President and Chief Operating Officer, Group Vice President and Chief Financial Officer. Mr. Jastrow is also a director and serves on the compensation committee of KB Home and MGIC Investment Corporation. Mr. Jastrow formerly served as Non-Executive Chairman of Forestar Group, Inc. Mr. Jastrow's executive experience and service as director of other companies enable him to make valuable contributions to our board of directors and particularly well suited to be the lead independent director.

Jack T. Taylor has served as a director of our general partner since July 2013. Mr. Taylor is currently a director of Sempra Energy and Murphy USA Inc. Additionally, Mr. Taylor currently serves on the audit committee of Sempra Energy and Murphy USA Inc. Mr. Taylor was a partner of KPMG LLP for 29 years, where from 2005 to 2010 he served as KPMG's Chief Operating Officer-Americas and Executive Vice Chair of U.S. Operations and from 2001 to 2005 he served as the Vice Chairman of U.S. Audit and Risk Advisory Services. Mr. Taylor's extensive experience with financial and public accounting issues, his various leadership roles at KPMG LLP and his extensive knowledge of the energy industry make him a valuable resource to our board of directors.

Robert V. Deere has served as Chief Financial Officer of our general partner since October 2008. Mr. Deere served as Vice President, Accounting and Reporting at Royal Dutch Shell (Shell) from 2003 through 2008.

Edward T. Flynn has served as Executive Vice President of our general partner and President, Genesis Alkali since we acquired that business from Tronox Ltd. in September 2017 (where he also previously served as Executive Vice President). Prior to joining Tronox, Mr. Flynn served as President FMC Minerals. He was previously President of FMC's Industrial Chemicals Group. Mr. Flynn is a member of the Board of Directors and Chairman of the Board for ANSAC.

Richard R. Alexander has served as Vice President of our general partner since November 2014. Mr. Alexander is responsible for the commercial aspects of our marine transportation segment. Since 2008, Mr. Alexander has served in various capacities within our marine operations.

Karen N. Pape has served as Senior Vice President and Controller of our general partner since July 2007 and served as Vice President and Controller from May 2002 until July 2007.

Kristen O. Jesulaitis has served as an executive officer of our general partner since January 2017. Ms. Jesulaitis has served as our General Counsel since July 2011. She is responsible for all legal functions of Genesis, including acquisitions and commercial transactions, compliance and regulatory affairs, corporate governance, securities, and finance. Prior to joining Genesis, Ms. Jesulaitis was a partner at the law firm Akin Gump Strauss Hauer & Feld LLP principally engaged in the areas of corporate and securities law, with primary focus in the midstream energy sector.

William S. Goloway has served as Vice President of our general partner since January 2017. Mr. Goloway has been responsible for the commercial aspects of our offshore Gulf of Mexico assets from the time we acquired these offshore assets from Enterprise Products in 2015. Prior to this acquisition, Mr. Goloway served in various roles within the offshore group at Enterprise Products since 2005.

Garland G. Gaspard has served as Senior Vice President of our general partner since January 2017 and is responsible for the operational aspects of our onshore and offshore pipelines, rail facilities, terminals, offshore facilities and assets, engineering, trucking and health, safety, security and environmental compliance. Mr. Gaspard joined Genesis in 2015 as a result of our acquisition of the offshore Gulf of Mexico assets from Enterprise Products and has had responsibility for the operational aspects of our offshore assets since that time. Prior to this acquisition, Mr. Gaspard served in various capacities within Enterprise Products' operations including underground gas storage, natural gas liquids, natural gas pipelines and offshore operations.

Chad A. Landry has served as Vice President of our general partner since January 2017. Mr. Landry joined Genesis in 2013 and since that time has been responsible for all operational and commercial aspects of our sodium minerals and sulfur services segment. Prior to joining Genesis, he spent 14 years at Axiall Corporation (Georgia Gulf), most recently as Vice President - Chlor-Alkali & Vinyls.

Ryan S. Sims has served as Vice President of our general partner since January 2017. Mr. Sims joined Genesis in 2011 and is responsible for our finance, planning and corporate development functions. He has also previously been responsible for the operational and commercial aspects of our rail and terminals businesses. Prior to joining Genesis, Mr. Sims spent six years in the investment banking industry. Mr. Sims is the son of Grant E. Sims, our Chairman and Chief Executive Officer.

Table of Contents

Common Unit Ownership by Directors and Executive Officers

We encourage our directors and officers to own our common units, although we do not feel it is necessary to require them to own a minimum number. Certain of our directors and officers own substantial amounts of our securities, although any (or all) of them may sell, pledge or otherwise dispose of all or a portion of those securities at any time, subject to any applicable legal and company policy requirements. See Item 10. "Directors, Executive Officers and Corporate Governance-Board Leadership Structure and Risk Oversight-Risk Oversight."

Code of Ethics

We have adopted a Code of Business Conduct and Ethics that is applicable to, among others, the principal financial officer and the principal accounting officer. Our Code of Business Conduct and Ethics is posted at our website (www.genesisenergy.com), where we intend to report any changes or waivers.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our officers and directors of our general partner and persons who own more than ten percent of a registered class of our equity securities to file reports of ownership and changes in ownership with the SEC and the NYSE. Based solely on our review of the copies of such reports received by us, or written representations from certain reporting persons to us, we are aware of no filings that were not timely made.

Item 11. Executive Compensation

The Compensation Discussion and Analysis below discusses our compensation process, objectives and philosophy with respect to our Named Executive Officers ("NEOs"), for the fiscal year ended December 31, 2018.

Compensation Discussion and Analysis

Named Executive Officers

Our NEOs for 2018 were:

- Grant E. Sims, Chief Executive Officer;
- Robert V. Deere, Chief Financial Officer;
- Edward T. Flynn, Executive Vice President;
- Richard R. Alexander, Vice President;
- Chad A. Landry, Vice President.

Board and Governance, Compensation and Business Development Committee

Our board of directors is responsible for, and effectively determines, compensation programs applicable to our NEOs and to the board itself. Our board of directors has delegated to the G&C Committee, of which a majority of the members are "independent," according to NYSE listing standards, the authority and responsibility to regularly analyze and evaluate our compensation policies, to determine the annual compensation of our NEOs, and to make recommendations to our board of directors with respect to such matters. As described in more detail below, the G&C Committee engaged BDO USA, LLP, or BDO, as its independent compensation adviser. We also utilize committees comprised solely of certain of our independent directors (i.e., the audit committee or special committees) to review and make recommendations with respect to certain matters such as obtaining exemptions from the "insider trading" rules under Section 16 of the Exchange Act in connection with certain acquisitions. Because the G&C Committee is comprised of all the members of our board of directors, excluding our CEO, determinations and recommendations by the G&C Committee are effectively determinations by our board of directors, which has approval authority for all such compensation matters. For a more detailed discussion regarding the purposes and composition of board committees, please see Item 10. "Directors, Executive Officers and Corporate Governance."

Committee/Board Process

Following the end of each calendar year, our CEO reviews the compensation of all the other NEOs and makes a proposal to the G&C Committee regarding their compensation. The CEO's proposal is based on (among other things) our financial results for the prior year, the relevant executive's areas of responsibility, market data provided by our independent compensation adviser and recommendations from the relevant executive's supervisor (if other than our CEO). The G&C Committee reviews the compensation of our CEO and the proposal of our CEO regarding the compensation of the other NEOs and makes a final determination (and a recommendation to our board of directors) regarding the compensation of our NEOs.

Table of Contents

Depending on the nature and quantity of changes made to that proposal, there may be additional G&C Committee meetings and discussions with our CEO in advance of that determination. Our board of directors has final approval authority for all such compensation matters.

Committee/Board Approval

The G&C Committee determines salaries, annual cash incentives and long-term awards for executive officers, taking into consideration the CEO's recommendation regarding the NEOs. In April, any applicable salary increases, retention bonuses and long-term incentive awards are made or granted.

Role of Compensation Consultant and Peer Group Analysis

The G&C Committee's charter authorizes it to retain independent compensation consultants from time to time to serve as a resource in support of its efforts to carry out certain duties. In 2018, the G&C Committee engaged BDO, an independent compensation consultant, to assist the G&C Committee in assessing and structuring competitive compensation packages for the executive officers that are consistent with our compensation philosophy. The G&C Committee assessed the independence of BDO pursuant to current exchange listing requirements and SEC guidance and concluded that no conflict of interest exists that would prevent BDO from serving as an independent consultant to the G&C Committee.

At the request of the G&C Committee, BDO reviewed and provided input on the compensation of our NEOs, trends in executive compensation, meeting materials circulated to the G&C Committee, and management's recommendations regarding executive compensation plans. BDO also developed assessments of market levels of compensation through an analysis of peer data and information disclosed in our peer companies' public filings, but did not determine or recommend the amount of compensation.

The peer group used for this market analysis in 2018 consisted of the following 17 companies in the energy industry: Boardwalk Pipeline Partners, Buckeye Partners, Calumet Specialty Products Partners, Crestwood Energy Partners, DCP Midstream, Enable Midstream Partners, Enbridge Energy Partners, EnLink Midstream Partners, Magellan Midstream Partners, MPLX, NGL Energy Partners, NuStar Energy, Summit Midstream Partners, Delek US Holdings, HollyFrontier Corp, SemGroup Corp, and Targa Resources Partners. These companies were selected as the compensation peer group for any or all of the following reasons:

1) they reflect our industry competitors for products and services;
2) they operate in similar markets or have comparable geographical reach;
3) they are of similar size and maturity to us; or
4) they are companies that have similar credit profiles to us and/or their growth or capital programs are similar to ours.

The G&C Committee reviews the peer group annually and may, from time to time, add or remove companies in order to assure the composition of the group meets the criteria outlined above.

The information that BDO compiled included compensation trends for MLPs and levels of compensation for similarly-situated executive officers of companies within this peer group. We believe that compensation levels of executive officers in our peer group are relevant to our compensation decisions because we compete with those companies for executive management talent.

Compensation Objectives and Philosophy

The primary objectives of our compensation program are to:

- encourage our executives to build and operate the partnership in a way that is aligned with our common unitholders' interests, focusing on growing total unitholder returns and growing the asset base with an emphasis on maintaining a focus on the long-term stability of the enterprise so as to not promote inappropriate risk taking;
- offer near-term and long-term compensation opportunities that are consistent with industry norms; and
- provide appropriate levels of retention to the executive team to ensure long-term continuity and stability for the successful execution of key growth initiatives and projects.

We strive to accomplish these objectives by providing all employees, including our NEOs, with a total compensation package that is market competitive and performance-based. In our assessment of the market competitiveness of compensation, we take into consideration the compensation offered by companies in our peer group described above, but we have not identified a specific percentile of peer company pay as a target. Rather, we use market information as one consideration in setting compensation along with individual performance, our financial and operational performance and our safety performance.

Table of Contents

We pay base salaries at levels that we feel are appropriate for the skills and qualities of the individual NEOs based on their past performance, current scope of responsibilities and future potential. The incentive-based components of each NEO’s compensation include annual cash bonus opportunities and participation in the long-term incentive program. The annual cash bonus rewards incremental operational and financial achievements required to meet investor expectations in the short-term while the long-term component focuses rewards to the long-term stability of the enterprise. Both incentive components are generally linked to base salary and are consistent in general with our understanding of market practice and with our judgment regarding each individual’s role in the organization.

As described in more detail below, we believe that the combination of base salaries, cash bonuses and long-term incentive plans provide an appropriate balance of short and long-term incentives, cash and non-cash based compensation and alignment of the incentives for our executives, including our NEOs, with the interests of our common unitholders.

The amount of compensation contingent on performance is a significant percentage of total compensation, therefore ensuring that business decisions and actions lead to the long-term growth and sustainability of the organization. Our bonus plan (including annual and retention bonuses) is driven by the generation of Available Cash before Reserves (as defined in Item. 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations-Financial Measures") (which is an important metric of value for our unitholders) and our safety record with the goal of retention of key employees and NEOs. Our long term incentive plan is also linked to our generation of Available Cash before Reserves and safety record, as well as the partnership's leverage ratio.

Elements of Our Compensation Program and Compensation Decisions for 2018

The primary elements of our compensation program are a combination of annual cash and long-term incentive-based compensation. For the year ended December 31, 2018, the elements of our compensation program for the NEOs consisted of the following:

- annual base salary
- discretionary annual cash and bonus awards
- annual grants under long-term incentive arrangements

Additionally, in order to attract qualified executive personnel, we may make one-time new-hire awards of equity.

Base Salaries

We believe that base salaries should provide a fixed level of competitive pay that reflects the executive officer’s primary duties and responsibilities, and which provides a foundation for incentive opportunities and benefit levels. As discussed above, the base salaries of our NEOs are reviewed annually by the G&C Committee, taking into account recommendations from our CEO regarding NEOs other than himself. We pay base salaries at a level that we feel is appropriate for the skills and qualities of the individual NEOs based on their past performance, current scope of responsibilities and future potential. Base salaries may be adjusted to achieve what is determined to be a reasonably competitive level or to reflect promotions, the assignment of additional responsibilities, individual performance or company performance. Salaries are also periodically adjusted based on analysis of peer group practices as described above.

In April 2018, the G&C Committee reviewed the assessments of market levels of compensation developed by BDO in conjunction with a discussion of individual performance and responsibilities. As a result of and taking into account current market conditions, the base salary of Mr. Sims was increased to $650,000, representing an increase from 2017 of 8%. This is his first salary increase since 2015. The base salaries of Messrs. Deere and Alexander were not increased from 2017 and remained unchanged in the amounts of $450,000 and $325,000, respectively. The base salary of Mr. Landry increased to $325,000, representing an increase from 2017 of 4% and the base salary of Mr. Flynn increased to $500,000, an increase of 4% from 2017.

Bonuses

Our NEOs typically participate in a bonus program, or the Bonus Plan, in which substantially all company employees participate. As designed by the G&C Committee, each NEO has an annual bonus target based on a stated percentage of his base salary. The targeted amount for the NEOs is established based on the analysis of market practices of the peer group and consideration of the level of salary and targeted long-term incentives for each NEO. Based on the G&C Committee's subjective review of 2018 operational and financial performance, in the context of total NEO

compensation, a discretionary bonus relating to 2018 was granted to Mr. Flynn of $730,000, in recognition of his leadership in his respective area and his individual contribution to the Partnership's performance. This bonus will be paid in March 2019, contingent upon Mr. Flynn's continued employment at that date. Further, it was determined by the G&C Committee that each NEO will be considered for a retention bonus for 2018, as further discussed below.
Our NEOs may participate in a retention bonus program for which certain key employees, managers and officers are eligible. These retention bonuses are discretionary and are awarded based on individual and company performance with the

goal of retaining key employees.  In 2018, Messrs. Flynn, Alexander, and Landry were granted retention bonuses of $500,000, $180,000, and $240,000, respectively, to be paid in the following installments: 50% in September 2019 and 50% in September 2020 contingent upon continued employment at those dates. Given the near-term economic challenges faced by us and the industry generally, we believe that these retention bonuses are an appropriate mechanism to incentivize key executives to remain with us so that we may benefit from their experience in the industry and other competitive opportunities available to them. Over the long term, the G&C committee intends to continue performance-based cash incentives as a cornerstone of our executive pay program.

Long-Term Incentive Compensation

We generally provide certain long-term compensation (cash and equity-based) to directors, officers, and certain employees through our long-term incentive compensation plans, or LTIPs. Our G&C Committee designs those awards to align the interests of plan participants with the interests of our long-term unitholders by promoting a sense of proprietorship and personal involvement in our development, growth, and financial success. Our LTIPs have given us flexibility to grant deferred compensation awards in the form of equity or cash-based compensation that vests outright or upon the satisfaction of one or more conditions that reward measurable service and performance, including the passage of time, continued employment, financial, and operating (including safety and environmental) metrics and the appreciation in our unit price over time.

For reasons discussed below, in 2018 our G&C Committee adopted our 2018 LTIP. Like our 2010 LTIP, our 2018 LTIP permits awards of equity-based compensation in the form of phantom units and distribution equivalent rights, or DERs. Phantom units are notional units representing unfunded and unsecured promises to pay to the participant a specified amount of cash based on the market value of our common units should specified vesting requirements be met. DERs are tandem rights to receive on a quarterly basis an amount of cash equal to the amount of distributions that would have been paid on outstanding phantom units had they been limited partner units issued by us. In addition, our 2018 LTIP permits cash-based awards.

Our G&C Committee administers our LTIPs and has broad authority to grant awards under and alter, amend, or terminate our LTIPs. For example, our G&C Committee has the authority to determine (i) who (if anyone) will receive awards from time to time as well as (ii) the size, nature, terms and conditions of such award. Our G&C Committee also has the authority to adopt, alter, and repeal rules, guidelines and practices relating to our LTIPs and interpret our LTIPs. Our board of directors can terminate the our LTIPs at any time.

Prior to 2018, we have provided long-term-equity-based compensation for our officers, directors, and certain employees primarily in the form of phantom units and distribution equivalent rights, or DERs, with vesting conditions that were tied to continuing increases in our (i) quarterly distribution rate consistent with our then existing business strategy and (ii) our unit price.

In October 2017, our management completed a strategic review and analysis of our capital allocation program and decided that, due to dramatic changes in how the market views MLP units, it was in the best long-term interest of our unitholders to further strengthen our balance sheet and enhance our financial flexibility. We therefore implemented a strategy to re-allocate capital by, among other things, reducing our quarterly distribution rate per unit to $0.50 (from $0.71). That distribution reset immediately resulted in all outstanding 2010 LTIP performance based awards effectively becoming worthless. Consequently, management and the G&C Committee determined that we should change the basic structure of LTIP awards to better align the interests of our employee plan participants with the interests of our long-term unitholders by awards of deferred cash compensation (in lieu of phantom units) allocated between service vesting and performance vesting.

During 2018, we awarded phantom units under our 2010 LTIP only to directors, all of which were service-based awards with no performance conditions.

During 2018, we also granted cash-based awards to certain officers and other employees under our 2018 LTIP, including our NEOs. We establish grant values for NEOs based on an analysis of market practices of our compensation peer group and consideration of the level of salary and targeted bonus for each NEO.

On April 10, 2018, the G&C Committee granted cash awards for both service and performance to each of our NEOs and certain employees under the 2018 LTIP.  All awards granted to NEOs were allocated as 20% service-based and 80% performance-based awards.  Contingent on continued employment on such date and satisfaction of the relevant performance standards, awards will vest between 20-420% of the cash grant value on April 10, 2021 and be paid in cash within 30 days thereafter. For performance awards, vesting is dependent on the satisfaction of relevant performance conditions and achievement of unit appreciation multiplier thresholds. Performance conditions include target levels of Available Cash before Reserves per unit, leverage ratios and safety metrics based upon such employee's business unit, each measured for the quarter ending or as of December 31, 2020, as applicable. Our unit appreciation multiplier is based upon the closing price of our common units on April 9, 2021 as compared to $19.8515, the closing price for our units on their grant date, April 10, 2018.

Table of Contents

For 2018, the G&C Committee established the following long-term incentive cash grant values for each of our NEOs:

| Name | 2018 Long-Term Incentive Cash Grant Value |
|---|---|
| Grant E. Sims | $ 1,800,000 |
| Robert V. Deere | $ 600,000 |
| Edward T. Flynn | $ 900,000 |
| Richard R. Alexander | $ 600,000 |
| Chad A. Landry | $ 400,000 |

Other Compensation and Benefits

We offer certain other benefits to our NEOs, including medical, dental, disability and life insurance, and contributions on their behalf to our 401(k) plan. NEOs participate in these plans on the same basis as all other employees. Other than the 401(k) plan, we do not sponsor a pension plan in which our NEOs are eligible to participate, and we do not provide post-retirement medical benefits that would be available to our NEOs.

No perquisites of any material nature are provided to our NEOs.

Tax and Accounting Implications

For our equity-based and cash-based compensation arrangements, we record compensation expense over the vesting period of the awards, as discussed further in Note 17 of our Consolidated Financial Statements in Item 8.

Compensation Committee Report

The G&C Committee has reviewed and discussed with management the Compensation Discussion and Analysis included above. Based on that review and discussion, the G&C Committee recommended to our board of directors that this Compensation Discussion and Analysis be included in this Form 10-K.

The foregoing report is provided by the following directors, who constitute the G&C Committee:

Kenneth M. Jastrow II, Chairman
James E. Davison
James E. Davison, Jr.
Sharilyn S. Gasaway
Conrad P. Albert
Jack T. Taylor

The information contained in this report shall not be deemed to be soliciting material or filed with the SEC or subject to the liabilities of Section 18 of the Exchange Act, except to the extent that we specifically incorporate it by reference into a document filed under the Securities Act or the Exchange Act.

Compensation Risk Assessment

Our board of directors does not believe that our compensation policies and practices for employees are reasonably likely to have a material adverse effect on us. We compensate all employees with a combination of competitive base salary and incentive compensation. Our board of directors believes that the mix and design of the elements of employee compensation do not encourage employees to assume excessive or inappropriate risk taking.

Our board of directors concluded that the following risk oversight and compensation design features guard against excessive risk-taking:

- the company has strong internal financial controls;
- base salaries are consistent with employees’ responsibilities so that they are not motivated to take excessive risks to achieve a reasonable level of financial security;
- the determination of incentive awards is based on a review of a variety of indicators of performance as well as a meaningful subjective assessment of personal performance, thus diversifying the risk associated with any single indicator of performance;

Table of Contents

- incentive awards are capped by the G&C Committee;
- compensation decisions include discretionary authority to adjust annual awards and payments, which further reduces any business risk associated with our plans; and
- long-term incentive awards are designed to provide appropriate awards for dedication to a corporate strategy that delivers long-term returns to unitholders.

Summary Compensation Table

The following Summary Compensation Table summarizes the total compensation paid or accrued to our NEOs in 2018, 2017 and 2016.

| Name & Principal Position | Year | Salary ($) | Bonus ($) (2) | Stock Awards ($) (3) | All Other Compensation ($) (4) | Total ($) |
|---|---|---|---|---|---|---|
| Grant E. Sims | 2018 | $650,000 | $ — | $ — | $ 193,201 | $843,201 |
| Chief Executive Officer | 2017 | 600,000 | 1,400,000 | 593,428 | 309,287 | 2,902,715 |
| (Principal Executive Officer) | 2016 | 600,000 | — | 1,744,069 | 274,531 | 2,618,600 |
| Robert V. Deere | 2018 | 450,000 | — | — | 137,864 | 587,864 |
| Chief Financial Officer | 2017 | 450,000 | 450,000 | 445,063 | 187,018 | 1,532,081 |
| (Principal Financial Officer) | 2016 | 450,000 | — | 1,017,376 | 162,940 | 1,630,316 |
| Edward T. Flynn (1) | 2018 | 500,000 | 930,958 | — | 19,976 | 1,450,934 |
| Executive Vice President | 2017 | 160,680 | 63,004 | — | 2,596 | 226,280 |
| Richard R. Alexander | 2018 | 325,000 | 260,000 | — | 136,308 | 721,308 |
| Vice President | 2017 | 325,000 | 640,000 | 741,761 | 212,304 | 1,919,065 |
| | 2016 | 325,000 | — | 726,693 | 154,883 | 1,206,576 |
| Chad A. Landry | 2018 | 325,000 | 178,750 | — | 46,106 | 549,856 |
| Vice President | 2017 | 312,500 | 443,750 | 311,560 | 85,770 | 1,153,580 |
| | 2016 | 300,000 | 157,500 | 290,683 | 47,811 | 795,994 |

(1) Mr. Flynn became an employee of the partnership on September 1, 2017 upon the acquisition of the Alkali business. The salary presented for 2017 represents his salary earned as an employee of the partnership.

(2) The amounts shown represent any retention bonuses vested and paid during 2018, as well as any cash or special bonus awards earned relative to 2018 but paid subsequent to December 31, 2018.

(3) The amounts shown in this column represent the aggregate grant date fair value for each NEO's phantom units granted under our 2010 Long-Term Incentive Plan. The grant date fair value of each award was determined in accordance with accounting guidance for equity-based compensation and is based on the probable outcome of any underlying performance conditions. Assumptions used in the calculation of these amounts are included in Note 17 to our Consolidated Financial Statements in Item 8.

(4) The following table presents the components of "All Other Compensation" for each NEO for the year ended December 31, 2018.

| Name | 401(k) Matching and Profit Sharing Contributions (a) | Insurance Premiums (b) | Other Compensation (c) | Totals |
|---|---|---|---|---|
| Grant E. Sims | $13,750 | $ 1,458 | $ 177,993 | $193,201 |
| Robert V. Deere | $30,250 | $ 1,458 | $ 106,156 | $137,864 |
| Edward T. Flynn | $19,272 | $ 704 | $ — | $19,976 |
| Richard R. Alexander | $30,250 | $ 1,458 | $ 104,600 | $136,308 |

| | | | | |
|---|---|---|---|---|
| Chad A. Landry | $27,266 | $ 1,458 | $ 17,382 | $46,106 |

The amounts in this table represent:

(a) Contributions by us to our 401(k) plan on each NEO's behalf.
(b) Term life insurance premiums paid by us on each NEO's behalf.
(c) This column includes cash distributions paid in connection with granted DERs under the 2010 LTIP during 2018.

Table of Contents

Grants of Plan-Based Awards in Fiscal Year 2018

The following table shows the cash-based awards granted to our NEOs in 2018.

| | | Estimated Future Payouts Under 2018 LTIP (1) | | |
|---|---|---|---|---|
| Name | Grant Date | Threshold | Target | Maximum |
| Grant E. Sims | 4/10/2018 | 1,080,000 | 1,800,000 | 3,240,000 |
| Robert V. Deere | 4/10/2018 | 360,000 | 600,000 | 1,080,000 |
| Edward T. Flynn | 4/10/2018 | 540,000 | 900,000 | 1,620,000 |
| Richard R. Alexander | 4/10/2018 | 360,000 | 600,000 | 1,080,000 |
| Chad A. Landry | 4/10/2018 | 240,000 | 400,000 | 720,000 |

(1) Represents the dollar amount of cash to be paid to each NEO under awards granted on April 10, 2018, if the company meets certain performance conditions (threshold, target and maximum) during the fourth quarter of 2020, assuming no forfeitures and considering a 1.0 UAM. See additional discussion in "Long-Term Incentive Compensation" above relating to the 2018 LTIP.

Employment Agreements

Richard R. Alexander

Mr. Alexander entered into an employment agreement in July 2008 relating to his employment and providing for a base salary which is subject to discretionary upward adjustments. Currently, the annual base salary of Mr. Alexander is $325,000. That agreement provides that Mr. Alexander is eligible to participate in all other benefit programs (e.g. health, dental, disability, life and/or other insurance plans) for which executive officers are generally eligible and severance benefits as disclosed in "Potential Payments upon Termination or Change of Control" below.

Outstanding Equity Awards at December 31, 2018

The following table presents the information regarding the outstanding equity awards to our NEOs previously issued under the 2010 LTIP at December 31, 2018.

| | | Stock Awards (4) | | | |
|---|---|---|---|---|---|
| Name | Grant Date | Equity Incentive Plan Awards: Number of Phantom Units that have not vested (#) (1) | Equity Incentive Plan Awards: Market Value of Phantom Units That Have Not Vested ($) | Equity Incentive Plan Awards: Number of Unearned Phantom Units That Have Not Vested (#) (1) | Equity Incentive Plan Awards: Market Value of Unearned Phantom Units That Have Not Vested ($) (2) |
| Grant E. Sims | 4/11/2017 | | | 18,327 | $ — |
| | 4/12/2016 | | | 57,089 | $ — |
| Robert V. Deere | 4/11/2017 | | | 13,745 | $ — |
| | 4/12/2016 | | | 33,302 | $ — |

| | | | | | | |
|---|---|---|---|---|---|---|
| Edward T. Flynn | 4/11/2017 | | | — | $ | — |
| | 4/12/2016 | | | — | $ | — |
| Richard R. Alexander | 4/11/2017 | | | 22,908 | $ | — |
| | 4/12/2016 | | | 23,787 | $ | — |
| Chad A. Landry [(3)] | 4/11/2017 | 3,848 | 79,769 | 5,774 | $ | — |
| | 4/12/2016 | 3,806 | 78,898 | 5,709 | $ | — |

94

Table of Contents

(1) The number of performance units in the table reflects a target performance payout. Service based units held by Mr. Landry do not specify threshold, target and maximum payouts levels. For additional information regarding Mr. Landry's units, please see note 3 below.

(2) Due to the distribution reset in 2017, the distribution rate per unit was reset during 2017 to a level well below the threshold trigger on the outstanding phantom units. Therefore, we have reflected a market value of these outstanding awards of $0 as of December 31, 2018.

(3) Phantom units outstanding for Mr. Landry include 3,806 and 3,848 service based units for 2016 and 2017 respectively. The remainder of the outstanding units held by Mr. Landry represented above are performance based units.

(4) The phantom units granted on 4/11/2016 have a vest date of 4/11/2019 and the phantom units granted on 4/11/2017 have a vest date of 4/11/2020.

Phantom Units Vested

The following table presents the information regarding the vesting of phantom units during the year ended December 31, 2018 with respect to our NEOs.

| Name | Phantom Unit Awards Number of Phantom Units Vested (#) | Value Realized on Vesting ($) |
|---|---|---|
| Grant E. Sims | 38,470 | $ — |
| Robert V. Deere | 14,427 | $ — |
| Edward T. Flynn | — | $ — |
| Richard R. Alexander | 12,824 | $ — |
| Chad A. Landry | 6,412 | $ 50,992 |

The phantom unit awards granted to our NEOs in 2015 vested on April 14, 2018. Pursuant to our 2010 LTIP, the value realized upon vesting was computed by multiplying the average closing price of our common units for the 20 trading days immediately prior to the date of vesting by the number of units that vested for the service based awards. Those phantom unit awards were paid in cash. As noted previously, due to the distribution reset during 2017, our performance based awards that vested during 2018 had a fair value of $0 upon vesting.

Termination or Change of Control Benefits

We consider maintaining a stable and effective management team to be essential to protecting and enhancing the best interests of us and our unitholders. To that end, we recognize that the possibility of a change of control or other acquisition event may raise uncertainty and questions among management, and such uncertainty could adversely affect our ability to retain our key employees, which would be to our unitholders’ detriment. Because our management team was built over time, as described above, and our NEOs became NEOs under different circumstances, the compensation and benefits awarded to our individual NEOs in the event of termination or a change of control varies. The employment agreement for Mr. Alexander provides certain compensation and benefits as an incentive to remain in our employ, enhancing our ability to call on and rely upon him in the event of a change of control. Mr. Alexander would not be entitled to severance benefits if terminated for cause. In extending these benefits, we considered a number of factors, including the prevalence of similar benefits adopted by other publicly traded MLPs. See “Potential Payments Upon Termination or Change of Control” below for further discussion of these benefits, including the definitions of certain terms such as change of control and cause.

We believe that the interests of unitholders will best be served if the interests of our management and unitholders are aligned. We believe the termination and change of control benefits described above strike an appropriate balance between the potential compensation payable and the objectives described above.

Potential Payments upon Termination or Change of Control

Mr. Alexander is entitled under his employment agreement to specified severance benefits under certain circumstances as discussed above.

Under a change of control and certain termination circumstances, each of our NEOs also will vest in any outstanding awards under our 2010 LTIP. Under the 2010 LTIP, a change of control occurs upon, in general, any sale of substantially all of the assets of us or our general partner or a merger, conversion, consolidation of us or our general partner or any other

Table of Contents

transaction resulting in a change in the beneficial ownership of more than 50% of the voting equity interests in our general partner.

Under a change of control under the 2018 LTIP, the unvested service tranche of the cash award granted shall become fully vested and the unvested performance tranche of the cash award granted shall vest at 150% of the performance metric.

If Mr. Alexander terminates his employment for good reason or we terminate his employment without cause, he would be entitled to (i) company payment of his COBRA health benefits for 12 months and (ii) monthly payments of his annual base salary due for the remainder of the renewal term of his employment agreement.

As used in Mr. Alexander's employment agreement, the terms "cause", "change of control", "good reason" and "renewal term" are generally described below:

- "Cause" means, in general, if the executive commits theft, embezzlement, forgery, any other act of dishonesty relating the executive's employment or violates our policies or any law, rule, or regulation applicable to us, is convicted of a felony or lesser crime having as its predicate element fraud, dishonesty, or misappropriation, fails to perform his duties under the employment agreement or commits an act or intentionally fails to act, which act or failure to act amounts to gross negligence or willful misconduct.
- "Good Reason" means, in general, following a change of control which results in a substantial diminution of the executive's duties, compensation, or benefits; executive's removal from position as Vice President (other than for cause, death or disability, or being offered an equivalent position); or our failure to make any payment to the executive required under the terms of his employment agreement.
- "Change of control" means, in general, any sale of equity in us or our general partner or sale of substantially all of our assets; any merger, conversion or consolidation of us or our general partner; or any other event that, in each of the foregoing cases, results in any persons or entities having the ability to elect a majority of the members of our board of directors (other than one or more of our executive officers or affiliates).
- "Renewal term" means, in general, each one-year term of employment beginning on July 18 of each year, absent either the Company or the executive giving the other party at least 90 days advance written notice of its intent not to renew the employment agreement between them.

Based upon a hypothetical termination date of December 31, 2018, the termination benefits for Messrs. Sims, Deere, Flynn, Alexander and Landry for voluntary termination or termination for cause would be zero.

Based upon a hypothetical termination date of December 31, 2018, the termination benefits for Mr. Alexander for termination without cause (other than as a result of death or disability) or for good reason would have been:

| | Richard R. Alexander |
|---|---|
| Severance pursuant to employment agreement | $ 325,000 |
| Healthcare | 25,447 |
| Total | $ 350,447 |

If termination occurs due to death or disability, Messrs. Sims, Deere, Flynn, Alexander and Landry would vest in outstanding phantom unit awards under our 2010 and 2018 LTIP plans. Utilizing the closing price of our common units for the twenty trading days prior to December 31, 2018 would result in payments under the 2010 and 2018 LTIP of the following amounts upon death or disability:

| | |
|---|---|
| Grant E. Sims | $1,800,000 |
| Robert V. Deere | $600,000 |
| Edward T. Flynn | $900,000 |
| Richard A. Alexander | $600,000 |
| Chad A. Landry | $558,667 |

Table of Contents

Based on a hypothetical simultaneous change of control and termination date of December 31, 2018, the change of control termination benefits for Messrs. Sims, Deere, Flynn, Alexander and Landry would have been as follows:

| | Grant E. Sims | Robert V. Deere | Edward T. Flynn | Richard R. Alexander | Chad A. Landry |
|---|---|---|---|---|---|
| Severance pursuant to employment agreement | $— | $— | | $325,000 | $— |
| Healthcare | $— | $— | | $25,447 | $— |
| Cash payment for vested phantom units under 2010 LTIP | — | — | — | — | $158,667 |
| Cash payment for vested awards under 2018 LTIP | $2,520,000 | $840,000 | $1,260,000 | $840,000 | $560,000 |
| Total | $2,520,000 | $840,000 | $1,260,000 | $1,190,447 | $718,667 |

Director Compensation in Fiscal Year 2018

The table below reflects compensation for our non-employee directors. Mr. Sims does not receive any compensation attributable to his status as a director.

| Name | Fees Earned or Paid in Cash ($) (1) | Stock Awards ($) (2) (3) | All Other Compensation ($) (4) | Total |
|---|---|---|---|---|
| James E. Davison | $ 80,000 | $100,000 | $ 20,473 | $200,473 |
| James E. Davison, Jr. | $ 80,000 | $100,000 | $ 20,473 | $200,473 |
| Sharilyn S. Gasaway | $ 102,500 | $112,500 | $ 23,031 | $238,031 |
| Kenneth M. Jastrow II | $ 92,500 | $112,500 | $ 23,031 | $228,031 |
| Conrad P. Albert | $ 92,500 | $102,500 | $ 20,986 | $215,986 |
| Jack T. Taylor | $ 92,500 | $102,500 | $ 20,986 | $215,986 |

(1) Amounts include annual retainer fees and fees for attending meetings.

(2) Amounts in this column represent the fair value of the awards of phantom units under our 2010 LTIP on the date of grant, as calculated in accordance with accounting guidance for equity-based compensation.

(3) Outstanding awards to directors at December 31, 2018 consist of phantom units granted under our 2010 LTIP. Messrs. James Davison and James Davison, Jr. each hold 10,507 outstanding phantom units, Messrs. Jastrow, Albert, Taylor and Ms. Gasaway hold 11,819, 10,769, 10,769 and 11,819 outstanding phantom units, respectively.

(4) Amounts in this column represent the amounts paid for tandem DERs related to outstanding phantom units granted under our 2010 LTIP.

Directors who are not officers of our general partner are entitled to a base compensation of $180,000 per year, with $80,000 paid in cash and $100,000 paid in phantom units. Cash is paid, and phantom units are awarded, on the first day of each calendar quarter. The number of phantom units awarded is determined by dividing the closing market price of our units on the date of the award into the amount to be paid in phantom units. So long as he or she is a director on the relevant date of determination, each director will receive: (i) a quarterly distribution equal to the number of phantom units held by such director multiplied by the quarterly distribution amount we will pay in respect of each of our outstanding common units on such distribution date, and (ii) on the third anniversary of each award date for such director, an amount equal to the number of phantom units granted to such director on such award date multiplied by the average closing price of our common units for the 20 trading days ending on the day immediately preceding such anniversary date.

The lead director and chairpersons of the audit committee and G&C Committee receive an additional amount of base compensation split equally between cash and phantom units, which cash compensation is paid in equal quarterly installments. Such additional amount is $10,000 for the lead director, $25,000 for the chair of the audit committee and $15,000 for the chair of the G&C Committee.

In addition, each non-employee director receives additional cash compensation for each "Additional Meeting" (board and/or committee) in which he or she participates. Participation by a director in-person will entitle her/him to additional compensation of $2,500 per meeting, and participation by a director by means of telecommunication will entitle her/him to additional compensation of $2,000 per meeting. Such payments are made in conjunction with the quarterly payments of base compensation. Additional Meetings consist of (i) with respect to our board of directors any meetings (in-person or by telecommunication) other than (x) the four pre-set meetings of our board of directors for each calendar year and (y) brief follow-up telecommunication conferences relating to the Annual Report on Form 10-K or any Quarterly Report on Form 10-Q the company files with the SEC, and (ii) any committee meeting.

Table of Contents

CEO Pay Ratio

Our CEO to median employee pay ratio is calculated in accordance with the SEC's pay ratio rules, Item 402(u) of Regulation S-K, which requires the disclosure of (i) the median of the annual total compensation of all employees of the company (except the CEO), (ii) the annual total compensation for the CEO, and (iii) the ratio of these two amounts.

We identified the median employee initially as of December 31, 2017 as a part of our 2017 10-K disclosure, and have noted no significant changes to our employee population or employee compensation arrangements for the period ended December 31, 2018 that would result in a significant change in the pay ratio disclosure. As such, we have elected to utilize the same median employee and utilize their 2018 total cash compensation for the year ended December 31, 2018. As of December 31, 2018, the company had 2,130 employees, including 2,118 full-time employees, and 12 part-time and seasonal employees.

Consistent with Item 402(u), we initially excluded from our employees those individuals who provide services as independent contractors, based on application of the tests used for tax purposes as set forth in the Internal Revenue Service's "Publication 15A: Employer's Supplemental Tax Guide. We did not make any assumptions, adjustments, or estimates with respect to total cash compensation. We believe the use of total cash compensation for all employees is a consistently applied compensation measure because we do not widely distribute annual equity awards to employees. Since all of our employees are located in the United States, including the Commonwealth of Puerto Rico, and paid in U.S. dollars, we did not make any cost-of-living adjustments in identifying the median employee.

After identifying the median employee based on total cash compensation, we calculated the annual total compensation for that employee using the same methodology we use for our named executive officers as set forth in the 2018 Summary Compensation Table above in this 10-K filing. Mr. Sims, our CEO had 2018 annual total compensation of $843,201, as reflected in the Summary Compensation Table. Our median employee's annual total compensation for 2018 was $118,176. Based on this information, Mr. Sims' total annual compensation was approximately seven times that of our median employee in 2018 or 7:1.

Table of Contents

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters
Beneficial Ownership of Partnership Units
The following table sets forth certain information as of February 28, 2019, regarding the beneficial ownership of our units by beneficial owners of 5% or more by class of unit and by directors and the executive officers of our general partner and by all directors and executive officers as a group. This information is based on data furnished by the persons named.

| Name and Address of Beneficial Owner | Class A Common Units Amount and Nature of Beneficial Ownership [(1)] | Class A Common Units Percent of Class | Class B Common Units Amount and Nature of Beneficial Ownership | Class B Common Units Percent of Class |
|---|---|---|---|---|
| Conrad P. Albert | 5,000 | * | — | — |
| James E. Davison | 3,476,282 (2) | 2.8 % | 9,453 | 23.6 % |
| James E. Davison, Jr. | 5,323,932 (3) | 4.3 % | 13,648 | 34.1 % |
| Sharilyn S. Gasaway | 279,445 | * | 1,081 | 2.7 % |
| Kenneth M. Jastrow II | 50,000 | * | — | — |
| Jack T. Taylor | 12,865 | * | — | — |
| Grant E. Sims | 3,000,000 (4) | 2.4 % | 7,087 | 17.7 % |
| Robert V. Deere | 829,987 | * | 1,052 | 2.6 % |
| Edward T. Flynn | 28,216 | * | — | — |
| Richard R. Alexander | 15,500 (5) | * | — | — |
| Karen N. Pape | 152,131 | * | — | — |
| Kristen O. Jesulaitis | — | * | — | — |
| Ryan S. Sims | 4,300 | * | — | — |
| William S. Goloway | 2,400 | * | — | — |
| Garland G. Gaspard | 1,247 | * | — | — |
| Chad A. Landry | 20,000 | * | — | — |
| All directors and executive officers as a group (16 in total) | 13,201,305 | 10.8 % | 32,321 | 80.8 % |
| | | | | |
| Steven K. Davison | 1,892,398 (6) | 1.5 % | 7,676 | 19.2 % |
| Chickasaw Capital Management, LLC | 10,903,352 | 8.9 % | — | |
| OppenheimerFunds, Inc. | 16,568,057 | 13.5 % | — | |
| Alerian MLP ETF | 10,845,157 | 8.9 % | — | |
| Clearbridge Investments, LLC | 9,800,863 | 8.0 % | — | |
| Harvest Fund Advisors, LLC | 6,239,022 | 5.1 % | | |

*Less than 1%

(1) The Class B Common Units, which also are included in the Class A Common Unit total, are identical in most respects to the Class A Common Units and have voting and distribution rights equivalent to those of the Class A Common Units. In addition, the Class B Common Units have the right to elect all of our board of directors and are convertible into Class A Common Units under certain circumstances, subject to certain exceptions.

(2) Mr. Davison pledged 1,049,406 of these Class A Common Units as collateral for a loan from a bank. In addition to his direct ownership interests, Mr. Davison is the sole stockholder of Terminal Services, Inc., which owns 1,010,835 Class A Common Units.

(3)

Mr. Davison, Jr. pledged 1,164,370 of these Class A Common Units as collateral for a loan from a bank. 1,339,383 of these Class A Common Units are held by trusts for Mr. Davison's children. 187,856 of these Class A Common Units are held by the James E. and Margaret A. B. Davison Special Trust.

(4) Mr. Sims pledged 1,450,000 of these Class A Common Units as collateral for loans from a bank.

(5) Mr. Alexander pledged 10,000 Class A Common Units as collateral for margin brokerage accounts.

(6) Includes 147,941 Class A Common units held by the Steven Davison Family Trust.

Except as noted, each unitholder in the above table is believed to have sole voting and investment power with respect to the units beneficially held, subject to applicable community property laws.

Table of Contents

With regards to our Class A Convertible Preferred Units, beneficial owners include Rodeo Finance Aggregator LLC and GSO Rodeo Holdings LP, each of whom beneficially owns 12,486,299 Class A Convertible Preferred Units as of February 28, 2019.

The mailing address for Genesis Energy, LLC and all officers and directors is 919 Milam, Suite 2100, Houston, Texas, 77002.

Beneficial Ownership of General Partner Interest

Genesis Energy, LLC owns a non-economic general partner interest in us. Genesis Energy, LLC is our wholly-owned subsidiary.

## Item 13. Certain Relationships and Related Transactions, and Director Independence

Transactions with Related Persons

Our CEO, Mr. Sims owns an aircraft, which is used by us for business purposes in the course of operations. We pay Mr. Sims a fixed monthly fee and reimburse the aircraft management company for costs related to our usage of the aircraft, including fuel and the actual out-of-pocket costs. In connection with this arrangement, we made payments to Mr. Sims totaling $0.7 million, during 2018. Based on current market rates for chartering of private aircraft under long-term, priority arrangements with industry recognized chartering companies, we believe that the terms of this arrangement are no worse than what we could have expected to obtain in an arms-length transaction.

Family members of certain of our executive officers and directors may work for us from time to time. In 2018, Mr. Sims (our CEO and a director) had two sons that worked for us- one as vice president of finance, planning and corporate development and the other as vice president and general manager of refined products. Mr. James Davison, Sr. (a director) had one son (who is also a brother of James E. Davison, Jr., a director), that worked as a director in our onshore facilities and transportation department in 2018. In the aggregate, these family members received total W-2 compensation of less than $1,100,000.

Director Independence

Because we are a limited partnership, the listing standards of the NYSE do not require that we have a majority of independent directors (although at least a majority of the members of our board of directors is independent,as defined by the NYSE rules) or that we have either a nominating committee or a compensation committee of our board of directors. We are, however, required to have an audit committee consisting of at least three members, all of whom are required to be “independent” as defined by the NYSE.

Under NYSE rules, to be considered independent, our board of directors must determine that a director has no material relationship with us other than as a director. The rules specify the criteria by which the independence of directors will be determined, including guidelines for directors and their immediate family members with respect to employment or affiliation with us or with our independent public accountants. Our board of directors has determined that each of Ms. Gasaway and Messrs. Jastrow, Albert and Taylor is an independent director under the NYSE rules. See Item 10. “Directors, Executive Officers and Corporate Governance” for additional discussion relating to our directors and director independence.

## Item 14. Principal Accounting Fees and Services

The following table summarizes the fees for professional services rendered by Ernst & Young and Deloitte & Touche LLP for the years ended December 31, 2018 and 2017.

| | 2018 | 2017 |
|---|---|---|
| | (in thousands) | |
| Audit Fees [(1)] | $2,977 | $2,867 |
| Tax Fees [(2)] | — | 1,308 |
| All Other Fees [(3)] | 8 | 4 |
| Total | $2,985 | $4,179 |

(1) Includes fees for the annual audit and quarterly reviews (including internal control evaluation and reporting), SEC registration statements and accounting and financial reporting consultations and research work regarding Generally Accepted Accounting Principles. In addition, this includes fees paid to both Ernst & Young and Deloitte during

2017, as effective June 2017 we changed our registered independent public accounting firm from Deloitte to Ernst & Young.

(2) Includes fees for tax return preparation and tax consultations.

(3) Includes fees associated with licenses for accounting research software.

Pre-Approval Policy

The services by Ernst & Young and Deloitte in 2018 and 2017 were pre-approved in accordance with the pre-approval policy and procedures adopted by the audit committee. This policy describes the permitted audit, audit-related, tax and other services, which we refer to collectively as the Disclosure Categories that the independent auditor may perform. The policy requires that each fiscal year, a description of the services, or the Service List expected to be performed by the independent auditor in each of the Disclosure Categories in the following fiscal year be presented to the audit committee for approval.

Any requests for audit, audit-related, tax and other services not contemplated on the Service List must be submitted to the audit committee for specific pre-approval and cannot commence until such approval has been granted. Normally, pre-approval is provided at regularly scheduled meetings.

In considering the nature of the non-audit services provided by Ernst & Young and Deloitte in 2018 and 2017, the audit committee determined that such services are compatible with the provision of independent audit services. The audit committee discussed these services with Ernst & Young, Deloitte and management of our general partner to determine that they are permitted under the rules and regulations concerning auditor independence promulgated by the SEC to implement the Sarbanes-Oxley Act of 2002, as well as the American Institute of Certified Public Accountants.

Table of Contents

Item 15. Exhibits and Financial Statement Schedules
(a)(1) Financial Statements
See "Index to Consolidated Financial Statements and Financial Statement Schedules".
(a)(2) Financial Statement Schedules.
See "Index to Consolidated Financial Statements and Financial Statement Schedules".
(a)(3) Exhibits

| | |
|---|---|
| 2.1 | Purchase and Sale Agreement, dated July 16, 2015, by and between Genesis Energy L.P. and Enterprise Products Operating, LLC (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K/A dated July 16 2015, File No. 001-12295). |
| 2.2 | Stock Purchase Agreement, dated August 2, 2017, by and among Genesis Energy, L.P., Tronox US Holdings, Inc., Tronox Alkali Corporation and, for the purposes set forth therein, Tronox Limited (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K dated August 7, 2017, File No. 001-12295). |
| 3.1 | Certificate of Limited Partnership of Genesis Energy, L.P. (incorporated by reference to Exhibit 3.1 to Amendment No. 2 of the Registration Statement on Form S-1, File No. 333-11545). |
| 3.2 | Amendment to the Certificate of Limited Partnership of Genesis Energy, L.P. (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2011, File No. 001-12295). |
| 3.3 | Fifth Amended and Restated Agreement of Limited Partnership of Genesis Energy, L.P. (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K dated January 3, 2011, File No. 001-12295). |
| 3.4 | First Amendment to Fifth Amended and Restated Agreement of Limited Partnership of Genesis Energy, L.P., dated September 1, 2017 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K dated September 7, 2017, File No. 001-12295). |
| 3.5 | Second Amendment to Fifth Amended and Restated Agreement of Limited Partnership of Genesis Energy, L.P., dated December 31, 2017 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K dated January 4, 2018, File No. 001-12295). |
| 3.6 | Certificate of Conversion of Genesis Energy, Inc., a Delaware corporation, into Genesis Energy, LLC, a Delaware limited liability company (incorporated by reference to Exhibit 3.1 to Form 8-K dated January 7, 2009, File No. 001-12295). |
| 3.7 | Certificate of Formation of Genesis Energy, LLC (formerly Genesis Energy, Inc.) (incorporated by reference to Exhibit 3.2 to Form 8-K dated January 7, 2009, File No. 001-12295). |
| 3.8 | Second Amended and Restated Limited Liability Company Agreement of Genesis Energy, LLC dated December 28, 2010 (incorporated by reference to Exhibit 3.2 to Form 8-K dated January 3, 2011, File No. 001-12295). |
| 3.9 | Certificate of Incorporation of Genesis Energy Finance Corporation, dated as of November 26, 2006 (incorporated by reference to Exhibit 3.7 to Registration Statement on Form S-4 filed on September 26, 2011, File No. 333-177012). |
| 3.10 | Bylaws of Genesis Energy Finance Corporation (incorporated by reference to Exhibit 3.8 to Registration Statement on Form S-4 filed on September 26, 2011, File No. 333-177012). |
| 4.1 | Form of Unit Certificate of Genesis Energy, L.P. (incorporated by reference to Exhibit 4.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-12295). |
| 4.2 | Form of Common Unit Certificate of Genesis Energy, L.P. (incorporated by reference to Exhibit 4.1 to Form 10-K filed on March 17, 2008, File No. 001-12295) |
| 4.3 | Davison Unitholder Rights Agreement dated July 25, 2007 (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K dated July 31, 2007, File No. 001-12295). |
| 4.4 | |

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| | Amendment No. 1 to the Davison Unitholder Rights Agreement dated October 15, 2007 (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K dated October 19, 2007, File No. 001-12295). |
| 4.5 | Amendment No. 2 to the Davison Unitholder Rights Agreement dated December 28, 2010 (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K dated January 3, 2011, File No. 001-12295). |
| 4.6 | Davison Registration Rights Agreement dated July 25, 2007 (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K dated July 31, 2007, File No. 001-12295). |

Table of Contents

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| 4.7 | Amendment No. 1 to the Davison Registration Rights Agreement, dated November 16, 2007 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated November 16, 2007, File No. 001-12295). |
| 4.8 | Amendment No. 2 to the Davison Registration Rights Agreement, dated December 6, 2007 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated December 11, 2007, File No. 001-12295). |
| 4.9 | Amendment No. 3 to the Davison Registration Rights Agreement, dated as of December 28, 2010 (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K dated January 3, 2011, File No. 001-12295). |
| 4.10 | Registration Rights Agreement, dated as of December 28, 2010, by and among Genesis Energy, L.P. and the former unitholders of Genesis Energy, LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-k dated January 3, 2011, File No. 001-12295). |
| 4.11 | Registration Rights Agreement, dated September 1, 2017, by and among Genesis Energy, L.P., GSO Rodeo Holdings LP and Rodeo Finance Aggregator LLC (incorporated by reference from Exhibit 4.1 to the Company's Current Report on Form 8-K filed on September 7, 2017, File No. 001-12295). |
| 4.12 | Indenture for 5.75% Senior Subordinated Notes due 2021, dated February 8, 2013 among Genesis Energy, L.P., Genesis Energy Finance Corporation, certain subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K dated February 11, 2013, File No. 001-12295). |
| 4.13 | First Supplemental Indenture for 5.75% Senior Subordinated Notes due 2021, dated as of February 19, 2014, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.14 to Form 10-K filed on February 27, 2014, File No. 001-12295). |
| 4.14 | Second Supplemental Indenture for 5.75% Senior Subordinated Notes due 2021, dated as of May 7, 2014, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.27 to Form 10-K filed on February 27, 2015, File No. 001-12295). |
| 4.15 | Third Supplemental Indenture for 5.75% Senior Subordinated Notes due 2021, dated as of October 15, 2014, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.28 to Form 10-K filed on February 27, 2015, File No. 001-12295). |
| 4.16 | Fourth Supplemental Indenture for 5.75% Senior Subordinated Notes due 2021, dated as of December 17, 2014, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.29 to Form 10-K filed on February 27, 2015, File No. 001-12295). |
| 4.17 | Fifth Supplemental Indenture for 5.75% Senior Subordinated Notes due 2021, dated as of January 22, 2015, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.30 to Form 10-K filed on February 27, 2015, File No. 001-12295). |
| 4.18 | Sixth Supplemental Indenture for 5.75% Senior Subordinated Notes due 2021, dated as of February 19, 2015, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.31 to Form 10-K filed on February 27, 2015, File No. 001-12295). |
| 4.19 | Seventh Supplemental Indenture for 5.75% Senior Subordinated Notes due 2021, dated as of February 19, 2015, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.32 to Form 10-K filed on February 27, 2015, File No. 001-12295). |
| 4.20 | Eighth Supplemental Indenture for 5.75% Senior Notes due 2021, dated as of June 26, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National |

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|---|---|
| | Association, as trustee (incorporated by reference to Exhibit 4.8 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015, File No. 001-12295). |
| 4.21 | Ninth Supplemental Indenture for 5.75% Senior Notes due 2021, dated as of July 15, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.9 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015, File No. 001-12295). |
| 4.22 | Tenth Supplemental Indenture for 5.75% Senior Notes due 2021, dated as of September 22, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National association, as trustee (incorporated by reference to Exhibit 4.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2015, File No. 001-12295). |

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| 4.23 | Eleventh Supplemental Indenture for 5.75% Senior Notes due 2021, dated as of December 11, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National association, as trustee (incorporated by reference to Exhibit 4.41 to Form 10-K filed on February 26, 2016, File No. 001-12295). |
| 4.24 | Twelfth Supplemental Indenture for 5.75% Senior Notes due 2021, dated as of March 10, 2016, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National association, as trustee (incorporated by reference to Exhibit 4.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, File No. 001-12295). |
| 4.25 | Thirteenth Supplemental Indenture for 5.75% Senior Notes due 2021, dated as of June 29, 2017, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National association, as trustee. |
| 4.26 | Fourteenth Supplemental Indenture for 5.75% Senior Notes due 2021, dated as of November 13, 2017, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National association, as trustee. |
| 4.27 | Indenture for 5.625% Senior Notes due 2024, dated May 15, 2014, among Genesis Energy, L.P., Genesis Energy Finance Corporation, certain subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company’s Current Report on Form 8-K dated May 15, 2014, File No. 001-12295). |
| 4.28 | Supplemental Indenture for the Issuer's 5.625% Senior Notes due 2024, dated as of May 15, 2014, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed on May 15, 2014, File No. 001-12295). |
| 4.29 | Second Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of October 15, 2014, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.35 to Form 10-K filed on February 27, 2015, File No. 001-12295). |
| 4.30 | Third Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of December 17, 2014, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.36 to Form 10-K filed on February 27, 2015, File No. 001-12295). |
| 4.31 | Fourth Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of January 22, 2015, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.37 to Form 10-K filed on February 27, 2015, File No. 001-12295). |
| 4.32 | Fifth Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of February 19, 2015, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.38 to Form 10-K filed on February 27, 2015, File No. 001-12295). |
| 4.33 | Sixth Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of February 19, 2015, by and among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.39 to Form 10-K filed on February 27, 2015, File No. 001-12295). |
| 4.34 | Seventh Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of June 26, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.6 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015, File No. 001-12295). |
| 4.35 | Eighth Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of July 15, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.7 to the Company's Quarterly Report on Form |

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|---|---|
| | 10-Q for the quarter ended June 30, 2015, File No. 001-12295). |
| 4.36 | Ninth Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of September 22, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2015, File No. 001-12295). |
| 4.37 | Tenth Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of December 11, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.52 to Form 10-K filed on February 26, 2016, File No. 001-12295). |

Table of Contents

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| 4.38 | Eleventh Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of March 10, 2016, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, File No. 001-12295). |
| 4.39 | Twelfth Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of June 29, 2017, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee. |
| 4.40 | Thirteenth Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of November 13, 2017, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee. |
| 4.41 | Fourteenth Supplemental Indenture for 5.625% Senior Notes due 2024, dated as of August 28, 2018, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 of the Company's Current Quarterly Report on Form 10-Q for the quarter ended September 30, 2018, File No. 001-12295). |
| 4.42 | Indenture, dated May 21, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K dated May 21, 2015, File No. 001-12295). |
| 4.43 | Supplemental Indenture for the Issuers' 6.000% Senior Notes due 2023, dated May 21, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (including the form of the Notes) (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K dated May 21, 2015, File No. 001-12295). |
| 4.44 | Second Supplemental Indenture for 6.000% Senior Notes due 2023, dated as of June 26, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015, File No. 001-12295). |
| 4.45 | Third Supplemental Indenture for 6.000% Senior Notes due 2023, dated as of July 15, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015, File No. 001-12295). |
| 4.46 | Fourth Supplemental Indenture for 6.75% Senior Notes due 2022, dated as of July 23, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee to the Indenture dated as of May 21, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K dated July 28, 2015, File No. 001-12295). |
| 4.47 | Fifth Supplemental Indenture for 6.000% Senior Notes due 2023 and 6.75% Senior Notes due 2022, dated as of September 22, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2015, File No. 001-12295). |
| 4.48 | Sixth Supplemental Indenture for 6.000% Senior Notes due 2023 and 6.75% Senior Notes due 2022, dated as of December 11, 2015, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.59 to Form 10-K filed on February 26, 2016, File No. 001-12295). |
| 4.49 | Seventh Supplemental Indenture for 6.000% Senior Notes due 2023 and 6.75% Senior Notes due 2022, dated as of March 10, 2016, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, File No. 001-12295). |
| 4.50 | Eighth Supplemental Indenture for 6.000% Senior Notes due 2023 and 6.75% Senior Notes due 2022, dated as of June 29, 2017, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named |

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| | therein and U.S. Bank National Association, as trustee. |
| 4.51 | Ninth Supplemental Indenture for 6.50% Senior Notes due 2025, dated as of August 14, 2017, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference from Exhibit 4.2 to the Company's Current Report on Form 8-K filed on August 14, 2017, File No. 001-12295). |

105

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| 4.52 | Tenth Supplemental Indenture for 6.000% Senior Notes due 2023, 6.75% Senior Notes due 2022 and 6.50% Senior Notes due 2025, dated as of November 13, 2017, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee. |
| 4.53 | Eleventh Supplemental Indenture for 6.250% Senior Notes Due 2026, dated as of December 11, 2017, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K filed on December 11, 2017, File No. 001-12295). |
| 4.54 | Twelfth Supplemental Indenture for 6.000% Senior Notes due 2023, 6.75% Senior Notes due 2022, 6.50% Senior Notes due 2025, and 6.250% Senior Notes due 2026, dated as of August 28, 2018, among Genesis Energy, L.P., Genesis Energy Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 of the Company's Current Quarterly Report on Form 10-Q for the quarter ended September 30, 2018, File No. 001-12295). |
| 10.1 | Fourth Amended and Restated Credit Agreement, dated as of June 30, 2014, among Genesis Energy, L.P. as borrower, Wells Fargo Bank, National Association, as administrative agent, Bank of America, N.A. and Bank of Montreal as co-syndication agents, U.S. Bank National Association as documentation agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K dated July 3, 2014, File No. 001-12295). |
| 10.2 | First Amendment to Fourth Amended and Restated Credit Agreement, dated August 25, 2014, among Genesis Energy, L.P. as borrower, Wells Fargo Bank, National Association, as administrative agent, Bank of America, N.A. and Bank of Montreal as co-syndication agents, U.S. Bank National Association as documentation agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K dated August 29, 2014, File No. 001-12295). |
| 10.3 | Second Amendment to Fourth Amended and Restated Credit Agreement and Joinder Agreement, dated as of July 17, 2015, among Genesis Energy, L.P. as borrower, Wells Fargo Bank, National Association, as administrative agent and issuing bank, Bank of America, N.A. and Bank of Montreal as co-syndication agents, U.S. Bank National Association as documentation agent, and the lenders party thereto (incorporated by reference to Exhibit 10.3 to Form 10-K filed on February 26, 2016, File No. 001-12295). |
| 10.4 | Third Amendment to Fourth Amended and Restated Credit Agreement, dated as of September 17, 2015, among Genesis Energy, L.P. as borrower, Wells Fargo Bank, National Association, as administrative agent and issuing bank, Bank of America, N.A. and Bank of Montreal as co-syndication agents, U.S. Bank National Association as documentation agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K dated September 23, 2015, File No. 001-12295). |
| 10.5 | Fourth Amendment to Fourth Amended and Restated Credit Agreement and Joinder Agreement dated as of April 27, 2016 among Genesis Energy, L.P., as the borrower, Wells Fargo Bank, National Association, as administrative agent and issuing bank, Bank of America, N.A. and Bank of Montreal, as co-syndication agents, U.S. Bank National Association, as documentation agent, and the lenders party thereto. (incorporated by reference to Exhibit 10.1 to Form 8-K dated May 3, 2016, File No. 001-12295). |
| 10.6 | Fifth Amendment to Fourth Amended and Restated Credit Agreement and Second Amendment to Fourth Amended and Restated Guarantee and Collateral Agreement (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated May 15, 2017, File No. 001-12295). |
| 10.7 | Sixth Amendment to Fourth Amended and Restated Credit Agreement, dated July 28, 2017, among Genesis Energy, L.P., as borrower, Wells Fargo Bank National Association, as administrative agent, Bank of America, N.A. and Bank of Montreal as co-syndication agents, U.S. Bank National Association as documentation agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K dated August 7, 2017, File No. 001-12295). |
| 10.8 | Seventh Amendment to Fourth Amended and Restated Credit Agreement, dated as of August 28, 2018, among Genesis Energy, L.P., as the borrower, Wells Fargo Bank, National Association, as administrative agent and issuing bank, Bank of America, N.A. and Bank of Montreal, as co-syndication agents, U.S. Bank National Association, as documentation agent, and the lenders and other parties party thereto (incorporated by reference to Exhibit 10.1 to the Company's Report on Form 8-K filed on August 31, 2018, File No. 333-177012). |

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| 10.9 | Eighth Amendment to Fourth Amended and Restated Credit Agreement, dated as of October 11, 2018, among Genesis Energy, L.P., as the borrower, Wells Fargo Bank, National Association, as administrative agent and issuing bank, Bank of America, N.A. and Bank of Montreal, as co-syndication agents, U.S. Bank National Association, as documentation agent, and the lenders and other parties party thereto (incorporated by reference to Exhibit 10.1 to the Company's Report on Form 8-K filed on October 11, 2018, File No. 001-12295). |

Table of Contents

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| 10.10 | | Form of Indemnity Agreement, among Genesis Energy, L.P., Genesis Energy, LLC and each of the Directors of Genesis Energy, LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated March 5, 2010, File No. 001-12295). |
| 10.11 | | Equity Distribution Agreement, dated June 27, 2016, among Genesis Energy, L.P., RBC Capital Markets, LLC, BNP Paribas Securities Corp., Capital One Securities, Inc., Deutsche Bank Securities Inc., DNB Markets, Inc., Fifth Third Securities, Inc., Scotia Capital (USA) Inc. and SMBC Nikko Securities America, Inc. (incorporated by reference to Exhibit 1.1 to Form 8-K dated June 27, 2016, File No. 001-12295). |
| 10.12 | + | Genesis Energy, L.P. 2010 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2010, File No. 001-12295). |
| 10.13 | + | Genesis Energy, LLC 2010 Long-Term Incentive Plan Form of Directors Phantom Unit with DERs Agreement (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2013, File No. 001-12295). |
| 10.14 | + | Genesis Energy, LLC 2010 Long-Term Incentive Plan Form of Executive Phantom Unit with DERs Award – Officers (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, File No. 001-12295). |
| 10.15 | + | Genesis Energy, LLC 2010 Long-Term Incentive Plan Form of Employee Phantom Unit with DERs Agreement (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2010, File No. 001-12295). |
| 10.16 | + | Genesis Energy 2018 Long-Term Incentive Plan (incorporated by reference from Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, File No. 001-12295). |
| 10.17 | + | Form of Award for 2018 LTIP (General) (incorporated by reference from Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, File No. 001-12295) |
| 10.18 | + | Form of Award for 2018 LTIP (Alkali) (incorporated by reference from Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, File No. 001-12295) |
| 10.19 | + | Form of Award for 2018 LTIP (Marine) (incorporated by reference from Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, File No. 001-12295) |
| 10.20 | | Employment Agreement by and between DG Marine Transportation, LLC and Richard Alexander dated July 18, 2008 (incorporated by reference to Exhibit 10.22 to the Company's Annual Report on Form 10K dated February 27, 2015, File No. 001-12295). |
| 10.21 | | Class A Convertible Preferred Unit Purchase Agreement, dated August 2, 2017, by and between Genesis Energy, L.P., and the purchasers named on Schedule A thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated August 7, 2017, File No. 001-12295). |
| 10.22 | | Board Observer Agreement, dated September 1, 2017, by and among Genesis Energy, L.P., GSO Rodeo Holdings LP and Rodeo Finance Aggregator LLC (incorporated by reference from Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 7, 2017, File No. 001-12295). |
| 11.1 | | Statement Regarding Computation of Per Share Earnings (See Notes 2 and 13 of the Notes to the Consolidated Financial Statements). |
| *21.1 | | Subsidiaries of the Registrant. |
| *23.1 | | Consent of Ernst & Young LLP. |
| *23.2 | | Consent of Ernst & Young LLP. |
| *23.3 | | Consent of Deloitte & Touche LLP. |
| *23.4 | | Consent of Deloitte & Touche LLP. |
| *31.1 | | Certification by Chief Executive Officer Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934. |
| *31.2 | | Certification by Chief Financial Officer Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934. |
| *32.1 | | Certification by Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| *32.2 | | Certification by Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |

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| *95 | Mine Safety Disclosure Exhibit |
| *101.INS | XBRL Instance Document. |

Table of Contents

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| *101.SCH | XBRL Schema Document. |
| *101.CAL | XBRL Calculation Linkbase Document. |
| *101.LAB | XBRL Label Linkbase Document. |
| *101.PRE | XBRL Presentation Linkbase Document. |
| *101.DEF | XBRL Definition Linkbase Document. |

* Filed herewith
+ A management contract or compensation plan or arrangement.

Item 16. Form 10-K Summary

Not Applicable

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

GENESIS ENERGY, L.P.
(A Delaware Limited Partnership)

By: GENESIS ENERGY, LLC,
as General Partner

Date: February 28, 2019 By: /s/ GRANT E. SIMS
Grant E. Sims
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons in the capacities and on the dates indicated.

| NAME | TITLE (OF GENESIS ENERGY, LLC)* | DATE |
|---|---|---|
| /s/ GRANT E. SIMS<br>Grant E. Sims | Chairman of the Board, Director and Chief Executive Officer<br>(Principal Executive Officer) | February 28, 2019 |
| /s/ ROBERT V. DEERE<br>Robert V. Deere | Chief Financial Officer,<br>(Principal Financial Officer) | February 28, 2019 |
| /s/ KAREN N. PAPE<br>Karen N. Pape | Senior Vice President and Controller<br>(Principal Accounting Officer) | February 28, 2019 |
| /s/ CONRAD P. ALBERT<br>Conrad P. Albert | Director | February 28, 2019 |
| /s/ JAMES E. DAVISON<br>James E. Davison | Director | February 28, 2019 |
| /s/ JAMES E. DAVISON, JR.<br>James E. Davison, Jr. | Director | February 28, 2019 |
| /s/ SHARILYN S. GASAWAY<br>Sharilyn S. Gasaway | Director | February 28, 2019 |
| /s/ KENNETH M. JASTROW, II<br>Kenneth M. Jastrow, II | Director | February 28, 2019 |
| /s/ JACK T. TAYLOR<br>Jack T. Taylor | Director | February 28, 2019 |

*Genesis Energy, LLC is our general partner.

Table of Contents

Item 8. Financial Statements and Supplementary Data
GENESIS ENERGY, L.P.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS
AND FINANCIAL STATEMENT SCHEDULES

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Genesis Energy, LLC and Unitholders of Genesis Energy, L.P.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Genesis Energy, L.P. (the Partnership) as of December 31, 2018 and 2017, and the related consolidated statements of operations, comprehensive income(loss), partners' capital and cash flows for each of the two years in the period ended December 31, 2018, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership at December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Partnership's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated
February 28, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

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

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

/s/ Ernst & Young LLP
We have served as the Partnership's auditor since 2017.
Houston, Texas
February 28, 2019

Table of Contents

# REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Genesis Energy, LLC and Unitholders of Genesis Energy, L.P.

## Opinion on Internal Control over Financial Reporting

We have audited Genesis Energy, L.P.'s internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Genesis Energy, L.P. (the Partnership) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Partnership as of December 31, 2018 and 2017, and the related consolidated statements of operations, comprehensive income(loss), partners' capital and cash flows for each of the two years in the period ended December 31, 2018, and the related notes and our report dated February 28, 2019 expressed an unqualified opinion thereon.

## Basis for Opinion

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

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

## Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ Ernst & Young LLP
Houston, TX
February 28, 2019

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors of Genesis Energy, LLC and Unitholders of
Genesis Energy, L.P.
Houston, Texas

We have audited the accompanying consolidated statements of operations, partners’ capital, and cash flows of Genesis Energy, L.P. and subsidiaries (the "Partnership") for the year ended December 31, 2016. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the results of operations and cash flows of Genesis Energy, L.P. and subsidiaries for the year ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
February 27, 2017

Table of Contents

GENESIS ENERGY, L.P.
CONSOLIDATED BALANCE SHEETS
(In thousands)

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| ASSETS | | |
| CURRENT ASSETS: | | |
| Cash and cash equivalents | $ 10,300 | $ 9,041 |
| Accounts receivable—trade, net | 323,462 | 495,449 |
| Inventories | 73,531 | 88,653 |
| Other | 35,986 | 42,890 |
| Total current assets | 443,279 | 636,033 |
| FIXED ASSETS, at cost | 5,440,858 | 5,601,015 |
| Less: Accumulated depreciation | (1,023,825) | (734,986) |
| Net fixed assets | 4,417,033 | 4,866,029 |
| MINERALS LEASEHOLDS, net of accumulated depletion | 560,481 | 564,506 |
| NET INVESTMENT IN DIRECT FINANCING LEASES, net of unearned income | 116,925 | 125,283 |
| EQUITY INVESTEES | 355,085 | 381,550 |
| INTANGIBLE ASSETS, net of amortization | 162,602 | 182,406 |
| GOODWILL | 301,959 | 325,046 |
| OTHER ASSETS, net of amortization | 121,707 | 56,628 |
| TOTAL ASSETS | $ 6,479,071 | $ 7,137,481 |
| LIABILITIES AND PARTNERS' CAPITAL | | |
| CURRENT LIABILITIES: | | |
| Accounts payable—trade | $ 127,327 | $ 270,855 |
| Accrued liabilities | 205,507 | 185,409 |
| Total current liabilities | 332,834 | 456,264 |
| SENIOR SECURED CREDIT FACILITY | 970,100 | 1,099,200 |
| SENIOR UNSECURED NOTES, net of debt issuance costs | 2,462,363 | 2,598,918 |
| DEFERRED TAX LIABILITIES | 12,576 | 11,913 |
| OTHER LONG-TERM LIABILITIES | 259,198 | 256,571 |
| Total liabilities | 4,037,071 | 4,422,866 |
| MEZZANINE CAPITAL | | |
| Class A Convertible Preferred Units, 24,438,022 and 22,411,728 issued and outstanding at December 31, 2018 and 2017, respectively | 761,466 | 697,151 |
| COMMITMENTS AND CONTINGENCIES (Note 22) | | |
| PARTNERS' CAPITAL: | | |
| Common unitholders, 122,579,218 and 122,579,218 units issued and outstanding at December 31, 2018 and 2017, respectively | 1,690,799 | 2,026,147 |
| Accumulated other comprehensive income (loss) | 939 | (604) |
| Noncontrolling interests | (11,204) | (8,079) |
| Total partners' capital | 1,680,534 | 2,017,464 |
| TOTAL LIABILITIES, MEZZANINE CAPITAL AND PARTNERS' CAPITAL | $ 6,479,071 | $ 7,137,481 |

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

F-4

Table of Contents

GENESIS ENERGY, L.P.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per unit amounts)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| REVENUES: | | | |
| Offshore pipeline transportation services | $284,544 | $318,239 | $334,679 |
| Sodium minerals and sulfur services | 1,174,434 | 462,622 | 171,503 |
| Marine transportation | 219,937 | 205,287 | 213,021 |
| Onshore facilities and transportation | 1,233,855 | 1,042,229 | 993,290 |
| Total revenues | 2,912,770 | 2,028,377 | 1,712,493 |
| COSTS AND EXPENSES: | | | |
| Onshore facilities and transportation product costs | 1,037,688 | 866,458 | 823,524 |
| Onshore facilities and transportation operating costs | 89,042 | 102,189 | 101,103 |
| Marine transportation operating costs | 172,527 | 154,606 | 142,551 |
| Sodium minerals and sulfur services operating costs | 912,491 | 333,918 | 91,443 |
| Offshore pipeline transportation operating costs | 66,668 | 72,065 | 79,624 |
| General and administrative | 66,898 | 66,421 | 45,625 |
| Depreciation, depletion and amortization | 313,190 | 252,480 | 222,196 |
| Impairment expense | 126,282 | — | — |
| Gain on sale of assets | (42,264) | (40,311) | — |
| Total costs and expenses | 2,742,522 | 1,807,826 | 1,506,066 |
| OPERATING INCOME | 170,248 | 220,551 | 206,427 |
| Equity in earnings of equity investees | 43,626 | 51,046 | 47,944 |
| Interest expense | (229,191) | (176,762) | (139,947) |
| Other income (expense) | 5,023 | (16,715) | — |
| Income (loss) from operations before income taxes | (10,294) | 78,120 | 114,424 |
| Income tax benefit (expense) | (1,498) | 3,959 | (3,342) |
| NET INCOME (LOSS) | (11,792) | 82,079 | 111,082 |
| Net loss attributable to noncontrolling interests | 5,717 | 568 | 2,167 |
| NET INCOME (LOSS) ATTRIBUTABLE TO GENESIS ENERGY, L.P. | $(6,075) | $82,647 | $113,249 |
| Less: Accumulated distributions attributable to Class A Convertible Preferred Units | (69,801) | (21,995) | — |
| NET INCOME (LOSS) AVAILABLE TO COMMON UNITHOLDERS | $(75,876) | $60,652 | $113,249 |
| BASIC AND DILUTED NET INCOME (LOSS) PER COMMON UNIT: | | | |
| Basic and Diluted | $(0.62) | $0.50 | $1.00 |
| WEIGHTED AVERAGE OUTSTANDING COMMON UNITS: | | | |
| Basic and Diluted | 122,579 | 121,546 | 113,433 |

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

F-5

Table of Contents

GENESIS ENERGY, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(In thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Net income (loss) | (11,792) | 82,079 | 111,082 |
| Other comprehensive income (loss): | | | |
| Decrease (increase) in benefit plan liability | 1,543 | (604) | — |
| Total Comprehensive income (loss) | (10,249) | 81,475 | 111,082 |
| Comprehensive loss attributable to non-controlling interests | 5,717 | 568 | 2,167 |
| Comprehensive income (loss) attributable to Genesis Energy, L.P. | (4,532) | 82,043 | 113,249 |

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

Table of Contents

GENESIS ENERGY, L.P.
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(In thousands)

| | Number of Common Units | Partners' Capital | Noncontrolling Interest | Accumulated Other Comprehensive Loss | Total |
|---|---|---|---|---|---|
| December 31, 2015 | 109,979 | $2,029,101 | $ (8,350) | $ — | $2,020,751 |
| Net income (loss) | — | 113,249 | (2,167) | — | 111,082 |
| Cash distributions to partners, net | — | (310,039) | — | — | (310,039) |
| Cash contributions from noncontrolling interests | — | — | 236 | — | 236 |
| Issuance of common units for cash, net (Note 12) | 8,000 | 298,020 | — | — | 298,020 |
| December 31, 2016 | 117,979 | 2,130,331 | (10,281) | — | 2,120,050 |
| Net income (loss) | — | 82,647 | (568) | — | 82,079 |
| Cash distributions to partners, net | — | (321,875) | — | — | (321,875) |
| Cash contributions from noncontrolling interests | — | — | 2,770 | — | 2,770 |
| Issuance of common units for cash, net (Note 12) | 4,600 | 140,513 | — | — | 140,513 |
| Other comprehensive loss | — | — | — | (604) | (604) |
| Distributions to preferred unitholders | — | (5,469) | — | — | (5,469) |
| December 31, 2017 | 122,579 | 2,026,147 | (8,079) | (604) | 2,017,464 |
| Impact of adoption of ASC 606 | — | (3,550) | — | — | (3,550) |
| Partners' capital, January 1, 2018 | 122,579 | 2,022,597 | (8,079) | (604) | 2,013,914 |
| Net loss(1) | — | (6,075) | (5,717) | — | (11,792) |
| Cash distributions to partners, net | — | (257,416) | — | — | (257,416) |
| Cash contributions from noncontrolling interests | — | — | 2,592 | — | 2,592 |
| Other comprehensive income | — | — | — | 1,543 | 1,543 |
| Distributions to preferred unitholders | — | (68,307) | — | — | (68,307) |
| December 31, 2018 | 122,579 | $1,690,799 | $ (11,204) | $ 939 | $1,680,534 |

(1) Net loss includes $69.8 million attributable to preferred unitholders accumulated as of December 31, 2018.
The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents

GENESIS ENERGY, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| CASH FLOWS FROM OPERATING ACTIVITIES: | | | |
| Net income (loss) | $(11,792) | $ 82,079 | $ 111,082 |
| Adjustments to reconcile net income to net cash provided by operating activities - | | | |
| Depreciation, depletion and amortization | 313,190 | 252,480 | 222,196 |
| Provision for leased items no longer in use | — | 12,589 | — |
| Gain on sale of assets | (42,264 ) | (40,311 ) | — |
| Impairment expense | 126,282 | — | — |
| Amortization and write-off of debt issuance costs and premium or discount | 12,165 | 13,103 | 10,138 |
| Amortization of unearned income and initial direct costs on direct financing leases | (13,035 ) | (13,747 ) | (14,395 ) |
| Payments received under direct financing leases | 20,668 | 20,668 | 20,672 |
| Equity in earnings of investments in equity investees | (43,626 ) | (51,046 ) | (47,944 ) |
| Cash distributions of earnings of equity investees | 42,735 | 47,316 | 50,281 |
| Non-cash effect of long-term incentive compensation plans | 3,941 | (5,775 ) | 6,558 |
| Deferred and other tax benefits | 663 | (4,060 ) | 2,142 |
| Unrealized (gains) losses on derivative transactions | (11,795 ) | 10,943 | 1,287 |
| Other, net | (4,941 ) | (10,839 ) | 11,385 |
| Net changes in components of operating assets and liabilities, net of acquisitions (See Note 16) | (2,152 ) | 10,156 | (90,650 ) |
| Net cash provided by operating activities | 390,039 | 323,556 | 282,752 |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | | |
| Payments to acquire fixed and intangible assets | (195,367 ) | (250,593 ) | (463,100 ) |
| Cash distributions received from equity investees—return of investment | 28,979 | 35,582 | 36,939 |
| Investments in equity investees | (3,018 ) | (4,647 ) | — |
| Acquisitions | — | (1,325,759 ) | (25,394 ) |
| Contributions in aid of construction costs | — | 124 | 13,374 |
| Proceeds from asset sales | 310,099 | 85,722 | 3,609 |
| Other, net | — | — | (151 ) |
| Net cash used in (provided by) investing activities | 140,693 | (1,459,571 ) | (434,723 ) |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | | |
| Borrowings on senior secured credit facility | 980,700 | 1,458,700 | 1,115,800 |
| Repayments on senior secured credit facility | (1,109,800 ) | (1,637,700 ) | (952,600 ) |
| Proceeds from issuance of senior unsecured notes | — | 1,000,000 | — |
| Proceeds from issuance of Class A convertible preferred units, net | — | 726,419 | — |
| Repayment of senior unsecured notes | (145,170 ) | (204,830 ) | — |
| Debt issuance costs | (242 ) | (25,913 ) | (1,578 ) |
| Issuance of common units for cash, net | — | 140,513 | 298,020 |
| Contributions from noncontrolling interests | 2,592 | 2,770 | 236 |
| Distributions to common unitholders | (257,416 ) | (321,875 ) | (310,039 ) |
| Other, net | (137 ) | (57 ) | (1,734 ) |
| Net cash provided by (used in) financing activities | (529,473 ) | 1,138,027 | 148,105 |
| Net increase (decrease) in cash and cash equivalents | 1,259 | 2,012 | (3,866 ) |
| Cash and cash equivalents at beginning of period | 9,041 | 7,029 | 10,895 |
| Cash and cash equivalents at end of period | $ 10,300 | $ 9,041 | $ 7,029 |

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

Table of Contents

GENESIS ENERGY, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
1. Organization
We are a growth-oriented master limited partnership focused on the midstream segment of the crude oil and natural gas industry in the Gulf Coast region of the United States and in the Gulf of Mexico. We provide an integrated suite of services to refiners, crude oil and natural gas producers, and industrial and commercial enterprise and have a diverse portfolio of assets, including pipelines, offshore hub and junction platforms, Alkali Business, refinery-related plants, storage tanks and terminals, railcars, rail loading and unloading facilities, barges and other vessels, and trucks. We were formed in 1996 and are owned 100% by our limited partners. Genesis Energy, LLC, our general partner, is a wholly-owned subsidiary. Our general partner has sole responsibility for conducting our business and managing our operations. We conduct our operations and own our operating assets through our subsidiaries and joint ventures.
On September 1, 2017, we acquired our trona and trona-based exploring, mining, processing, soda ash production, marketing and selling business (our "Alkali Business") for approximately $1.325 billion in cash. We funded that acquisition and the related transaction costs with proceeds from a $750 million private placement of convertible preferred units, a $550 million public offering of notes, our revolving credit facility, and cash on hand. We report the results of our Alkali Business in our sodium minerals and sulfur services segment, which includes our Alkali Business as well as our legacy refinery services operations.
We currently manage our businesses through four divisions that constitute our reportable segments:

- Offshore pipeline transportation and processing of crude oil and natural gas in the Gulf of Mexico;
- Sodium minerals and sulfur services involving trona and trona-based exploring, mining, processing, soda ash production, marketing and selling activities, as well as processing of high sulfur (or “sour”) gas streams for refineries to remove the sulfur, and selling the related by-product, sodium hydrosulfide (or “NaHS,” commonly pronounced "nash");
- Onshore facilities and transportation, which include terminaling, blending, storing, marketing, and transporting crude oil, petroleum products, and CO2; and
- Marine transportation to provide waterborne transportation of petroleum products and crude oil throughout North America

2. Summary of Significant Accounting Policies
Basis of Consolidation and Presentation
The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2018 and 2017 and our results of operations, statements of comprehensive income(loss), changes in partners’ capital and cash flows for the years ended December 31, 2018, 2017 and 2016. All intercompany balances and transactions have been eliminated. The accompanying Consolidated Financial Statements include Genesis Energy, L.P. and its subsidiaries.
Except per unit amounts, or as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.
Joint Ventures
We participate in several joint ventures, including, in our offshore pipeline transportation segment, a 64% interest in Poseidon Oil Pipeline Company, L.L.C. (or "Poseidon"), a 25.7% interest in Neptune Pipeline Company, LLC and a 29% interest in Odyssey Pipeline L.L.C. (or "Odyssey"). We account for our investments in these joint ventures by the equity method of accounting. See Note 9.

Table of Contents

Use of Estimates

The preparation of our Consolidated Financial Statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. We based these estimates and assumptions on historical experience and other information that we believed to be reasonable under the circumstances. Significant estimates that we make include: (1) liability and contingency accruals, (2) estimated fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets, (3) estimates of future net cash flows from assets for purposes of determining whether impairment of those assets has occurred, and (4) estimates of future asset retirement obligations. Additionally, for purposes of the calculation of the fair value of awards under equity-based compensation plans, we make estimates regarding expected forfeiture rates of the rights and expected future distribution yield on our units. While we believe these estimates are reasonable, actual results could differ from these estimates. Changes in facts and circumstances may result in revised estimates.

Cash and Cash Equivalents

Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less. We have no requirement for compensating balances or restrictions on cash. We periodically assess the financial condition of the institutions where these funds are held and believe that our credit risk is minimal.

Accounts Receivable

We review our outstanding accounts receivable balances on a regular basis and record an allowance for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted.

Inventories

Our inventories are valued at the lower of cost and net realizable value. With the exception of our Alkali Business, cost is determined principally under the average cost method within specific inventory pools.

Within our Alkali Business, the cost of inventories are determined using the FIFO, except for materials and supplies which are recorded at average cost, and raw materials which are recorded at standard cost, which approximates actual cost.

Fixed Assets and Mineral Leaseholds

Property and equipment are carried at cost. Depreciation of property and equipment is provided using the straight-line method over the respective estimated useful lives of the assets. Asset lives are 5 to 40 years for pipelines and related assets, 20 to 30 years for marine vessels, 3 to 30 years for machinery and equipment, 3 to 7 years for transportation equipment, and 3 to 20 years for buildings and improvements, office equipment, furniture and fixtures and other equipment.

Interest is capitalized in connection with the construction of major facilities. The capitalized interest is recorded as part of the asset to which it relates and is amortized over the asset's estimated useful life.

Maintenance and repair costs are charged to expense as incurred. Costs incurred for major replacements and upgrades are capitalized and depreciated over the remaining useful life of the asset. Certain volumes of crude oil and refined products are classified in fixed assets, as they are necessary to ensure efficient and uninterrupted operations of the gathering businesses. These crude oil and refined products volumes are carried at their weighted average cost.

Long-lived assets are reviewed for impairment. An asset is tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to be generated from the use and ultimate disposal of the asset. If the carrying value is determined to not be recoverable under this method, an impairment charge equal to the amount the carrying value exceeds the fair value is recognized. Fair value is generally determined from estimated discounted future net cash flows.

Mineral leaseholds are depleted over their useful lives as determined under the units of production method. When it has been determined that a mineral property can be economically developed as a result of establishing proven and probable reserves, the costs incurred to develop such property through the commencement of production are capitalized.

Deferred Charges on Marine Transportation Assets

Our marine vessels are required by US Coast Guard regulations to be re-certified after a certain period of time, usually every five years. The US Coast Guard states that vessels must meet specified "seaworthiness" standards to maintain required operating certificates. To meet such standards, vessels must undergo regular inspection, monitoring, and maintenance, referred to as "dry-docking." Typical dry-docking costs include costs incurred to comply with regulatory and vessel classification inspection requirements, blasting and steel coating, and steel replacement. We defer and amortize these costs to maintenance and repair expense over the length of time that the certification is supposed to last.

Table of Contents

Asset Retirement Obligations
Some of our assets have contractual or regulatory obligations to perform dismantlement and removal activities, and in some instances remediation, when the assets are abandoned. In general, our asset retirement obligations relate to future costs associated with the disconnecting or removing of our crude oil and natural gas pipelines and platforms, $CO_2$ pipelines, barge decommissioning, removal of equipment and facilities from leased acreage and land restoration. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using our credit adjusted risk-free interest rate, and a corresponding amount capitalized by increasing the carrying amount of the related long-lived asset. The capitalized cost is depreciated over the useful life of the related asset. Accretion of the discount increases the liability and is recorded to expense. See Note 7.
Direct Financing Leasing Arrangements
For our direct financing leases, we record the gross finance receivable, unearned income and the estimated residual value of the leased pipelines. Unearned income represents the excess of the gross receivable plus the estimated residual value over the costs of the pipelines. Unearned income is recognized as financing income using the interest method over the term of the transaction and is included in onshore facilities and transportation revenue in the Consolidated Statements of Operations. The pipeline cost is not included in fixed assets.
We review our direct financing lease arrangements for credit risk. Such review includes consideration of the credit rating and financial position of the lessee. See Note 8.
Intangible and Other Assets
Intangible assets with finite useful lives are amortized over their respective estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset shall be amortized over the best estimate of its useful life. At a minimum, we will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required. We are amortizing our customer and supplier relationships, contract agreements, licensing agreements and trade name based on the period over which the asset is expected to contribute to our future cash flows. Generally, the contribution of these assets to our cash flows is expected to decline over time, such that greater value is attributable to the periods shortly after the acquisition was made. Intangible assets associated with lease or other items are being amortized on a straight-line basis.
We test intangible assets periodically to determine if impairment has occurred. An impairment loss is recognized for intangibles if the carrying amount of an intangible asset is not recoverable and its carrying amount exceeds its fair value. No impairment has occurred of intangible assets in any of the periods presented.
Costs incurred in connection with our credit facilities and their related amendments have historically been capitalized and amortized using the straight-line method over the term of the related debt. Use of the straight-line method does not differ materially from the “effective interest” method of amortization. Certain of our capitalized debt issuance costs related to our respective issuances of notes are classified as reductions in long-term debt.
Goodwill
Goodwill represents the excess of purchase price over fair value of net assets acquired. We evaluate, and test if necessary, goodwill for impairment annually at October 1, and more frequently if indicators of impairment are present. During the evaluation, we may perform a qualitative assessment of relevant events and circumstances to determine the likelihood of goodwill impairment. If it is deemed more likely than not that the fair value of the reporting unit is less than its carrying amount, we calculate the fair value of the reporting unit. Otherwise, further testing is not necessary. We may also elect to exercise our unconditional option to bypass this qualitative assessment, in which case we would also calculate the fair value of the reporting unit. If the calculated fair value of the reporting unit exceeds its carrying value including associated goodwill amounts, the goodwill is considered to be unimpaired and no impairment charge is required. If the fair value of the reporting unit is less than its carrying value including associated goodwill amounts, the goodwill of that reporting unit is considered to be impaired and a charge to earnings must be recorded. The impact to earnings is the excess amount of carrying value over fair value, however the charge is not to exceed the total amount of goodwill allocated to the reporting unit under evaluation. See Note 10 for further information.
Environmental Liabilities

We provide for the estimated costs of environmental contingencies when liabilities are probable to occur and a reasonable estimate of the associated costs can be made. Ongoing environmental compliance costs, including maintenance and monitoring costs, are charged to expense as incurred.

Equity-Based Compensation

Our phantom units issued under our 2010 Long-Term Incentive Plan result in the payment of cash to our employees or directors of our general partner upon exercise or vesting of the related award. The fair value of our phantom units is equal to the

Table of Contents

market price of our common units. Our phantom units include both service-based and performance-based awards. For our performance-based awards, our fair value estimates are weighted based on probabilities for each performance condition applicable to the award. See Note 17 for more information.

Revenue Recognition

We recognize revenue across our operating segments upon the satisfaction of of their respective performance obligations. Refer to Note 3 for additional details on what constitutes a performance obligation in each of our businesses.

Cost of Sales and Operating Expenses

Onshore facilities and transportation operating and product costs include the cost to acquire the product and the associated costs to transport it to our terminal facilities, including storing, or to a customer for sale. Other than the cost of the products, the most significant costs we incur relate to transportation utilizing our fleet of trucks, railcars, terminals, barges and other vessels , including personnel costs, fuel and maintenance of our or third-party owned equipment. Additionally, costs to operate and maintain the integrity of our onshore pipelines are included herein. When we enter into buy/sell arrangements concurrently or in contemplation of one another with a single counterparty, we reflect the amounts of revenues and purchases for these transactions on a net basis in our Consolidated Statements of Operations as onshore facilities and transportation revenues.

Marine operating costs consist primarily of employee and related costs to man the boats, barges, and vessels, maintenance and supply costs related to general upkeep of the boats, barges, and vessels, and fuel costs which are often rebillable and passed through to the customer.

The most significant operating costs in our sodium minerals and sulfur services segment consist of the costs to operate our trona extraction and soda ash processing facilities, NaHS plants located at various refineries, caustic soda used in the process of processing the refiner's sour gas, and costs to transport the soda ash, other alkali products, NaHS and caustic soda.

Pipeline operating costs consist primarily of power costs to operate pumping and platform equipment, personnel costs to operate the pipelines and platforms, insurance costs and costs associated with maintaining the integrity of our pipelines.

Income Taxes

We are a limited partnership, organized as a pass-through entity for federal income tax purposes. As such, we do not directly pay federal income tax. Our taxable income or loss, which may vary substantially from the net income or net loss we report in our Consolidated Statements of Operations, is included in the federal income tax returns of each partner.

Some of our corporate subsidiaries pay U.S. federal, state, and foreign income taxes. Deferred income tax assets and liabilities for certain operations conducted through corporations are recognized for temporary differences between the assets and liabilities for financial reporting and tax purposes. Changes in tax legislation are included in the relevant computations in the period in which such changes are effective. Deferred tax assets are reduced by a valuation allowance for the amount of any tax benefit not expected to be realized. Penalties and interest related to income taxes will be included in income tax expense in the Consolidated Statements of Operations.

Derivative Instruments and Hedging Activities

When we hold inventory positions in crude oil and petroleum products, we use derivative instruments to hedge exposure to price risk. Derivative transactions, which can include forward contracts and futures positions on the NYMEX, are recorded in the Consolidated Balance Sheets as assets and liabilities based on the derivative's fair value. Changes in the fair value of derivative contracts are recognized currently in earnings unless specific hedge accounting criteria are met. We must formally designate the derivative as a hedge and document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting. Accordingly, changes in the fair value of derivatives are included in earnings in the current period for (i) derivatives accounted for as fair value hedges; (ii) derivatives that do not qualify for hedge accounting and (iii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items. Changes in the fair value of cash flow hedges are deferred in Accumulated Other Comprehensive Income ("AOCI") and reclassified into earnings when the underlying position affects earnings.

In addition, we have determined that certain provisions in our Class A Convertible Preferred units represent an embedded derivative which must be bifurcated and recorded at fair value, with changes in fair value in respective periods being recorded in our Consolidated Statements of Operations. See Note 19 for further information on these items.

Fair Value of Current Assets and Current Liabilities

The carrying amount of other current assets and other current liabilities approximates their fair value due to their short-term nature.

Table of Contents

Pension benefits

As a result of our acquisition of our Alkali Business, we now sponsor a defined benefit plan. The defined benefit plan is accounted for using actuarial valuations as required by GAAP. We recognize the funded status of the defined pension plan on the balance sheet and recognize changes in the funded status that arise during the period but are not recognized as components of net periodic benefit cost within other comprehensive income or loss.

Business Acquisitions

For acquired businesses, we apply the acquisition method and generally recognize the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their estimated fair values on the date of acquisition. See Note 4 for more information regarding our acquisition accounting and recording of acquisition costs.

Recent and Proposed Accounting Pronouncements

We have adopted guidance under ASC Topic 606, Revenue from Contracts with Customers, and all related ASUs (collectively "ASC 606") as of January 1, 2018 utilizing the modified retrospective method of adoption. The adoption date for our material equity method investment in the Poseidon Oil Pipeline Company, LLC will follow the non-public business entity adoption date of January 1, 2019 for its stand-alone financial statements. Refer to Note 3 for further details.

In July 2015, the FASB issued guidance modifying the accounting for inventory. Under this guidance, the measurement principle for inventory will change from lower of cost or market value to lower of cost and net realizable value. The guidance defines net realizable value as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The guidance is effective for reporting periods after December 15, 2016, with early adoption permitted. We have adopted this guidance as of January 1, 2017 with no material impact on our consolidated financial statements.

In February 2016, the FASB issued guidance to improve the transparency and comparability among companies by requiring lessees to recognize a lease liability and a corresponding lease asset for virtually all lease contracts. The guidance also requires additional disclosure about leasing arrangements. The guidance is effective for interim and annual periods beginning after December 15, 2018 and requires a modified retrospective approach to adoption.

We have reviewed the practical expedients that are available to facilitate the adoption process. We have elected to take the "package" of practical expedients set out in the standard, which must be elected together. The items within the package stipulate that an entity need not reassess: (1) if expired or existing contracts contain leases, (2) lease classification for previously-assessed leases under ASC 840, and (3) initial direct costs for existing leases. We have also elected to adopt the practical expedient relating to the separation of lease and non-lease components as well as the easement and right of way expedient. Finally we have elected to utilize the optional transition method which allows the company to only apply the new lease standard at the date of adoption while comparative periods will be presented under the previous lease guidance. We will not adopt the hindsight practical expedient.

As a result of adopting the new lease standard, we expect an impact on our consolidated balance sheet from the recognition of a right-of-use asset and the corresponding lease liability of less than $250 million. We do not expect a material impact to partners capital as a result of our transition adjustment.

In August 2016, the FASB issued guidance that addresses how certain cash receipts and payments are presented and classified in the statement of cash flows under Topic 230, Statement of Cash flow, and other Topics. The guidance is effective for annual reporting periods, and interim periods therein, beginning after December 15, 2017. We have adopted this guidance as of January 1, 2018 using the retrospective transition method to each period presented on the Consolidated Statements of Cash Flows. We reclassified $15.3 million and $15.6 million from operating cash flows to investing cash flows for the years ended December 31, 2017 and 2016, respectively.

In March 2017, the FASB issued ASU 2017-07, Compensation-Retirement Benefits (Topic 715). ASU 2017-07 requires employers to separate the service cost component from the other components of net benefit cost in the period. The new standard requires the other components of net benefit costs (excluding service costs), be reclassified to "Other expense" from "General and administrative." We adopted this standard as of January 1, 2018. This standard is applied retrospectively. The effect was not material to our financial statements for the year ended December 31, 2018.

In January 2017, the FASB issued guidance to simplify the goodwill impairment testing at annual or interim periods. The guidance eliminates Step 2 from the goodwill impairment testing process, and any identified impairment charge would be simplified to be the difference between the carrying value and fair value of a reporting unit, but would not exceed the total amount of goodwill allocated to the reporting unit in question. The guidance is effective for annual reporting periods, and interim periods therein, beginning after December 15, 2019. We elected to early adopt this standard as of January 1, 2017. See Note 10 for further information.

Table of Contents

3. Revenue Recognition

Adoption of ASC 606 and its related Transition Effects

The modified retrospective method of adoption required us to apply ASC 606 to all new revenue contracts entered into after January 1, 2018 and revenue contracts that were not completed as of January 1, 2018. Our consolidated revenues for periods prior to January 1, 2018 were not revised and the cumulative effect of our adoption of ASC 606 was recorded as an adjustment to partners' capital at January 1, 2018. Based on this application, the following adjustments were made to our consolidated balance sheet as of January 1, 2018:

| | December 31, 2017 | Adjustments | January 1, 2018 |
|---|---|---|---|
| ASSETS | | | |
| Accounts receivable - trade, net | $495,449 | $ (48,028 ) | $447,421 |
| Inventories | 88,653 | 5,138 | 93,791 |
| Other assets, net of amortization | 56,628 | 59,204 | 115,832 |
| | | | |
| LIABILITIES AND CAPITAL | | | |
| Other long-term liabilities | 256,571 | 19,864 | 276,435 |
| | | | |
| Partners' capital | 2,026,147 | (3,550 ) | 2,022,597 |

Current Impact of New Revenue Recognition Guidance

The tables below summarize the impact of adoption on our consolidated balance sheet and statement of operations as of and for the year ended December 31, 2018:

| | As of December 31, 2018 | | |
|---|---|---|---|
| Consolidated Balance Sheet | As Reported | Without adoption of ASC 606 | Effect of Change Increase/(Decrease) |
| ASSETS | | | |
| Accounts receivable-trade, net | $323,462 | $371,490 | $ (48,028 ) |
| Inventories | 73,531 | 69,367 | 4,164 |
| Other Assets, net of amortization | 121,707 | 49,466 | 72,241 |
| | | | |
| LIABILITIES AND CAPITAL | | | |
| Other Long-Term Liabilities | 259,198 | 232,927 | 26,271 |
| Partners' Capital | 1,690,799 | 1,688,693 | 2,106 |

Table of Contents

| Consolidated Statement of Operations | Year ended December 31, 2018 As Reported | Without adoption of ASC 606 | Effect of Change Increase/(Decrease) |
|---|---|---|---|
| Offshore pipeline transportation services | $284,544 | $277,915 | $ 6,629 |
| Sodium minerals and sulfur services | 1,174,434 | 1,071,634 | 102,800 |
| Marine transportation | 219,937 | 219,937 | — |
| Onshore facilities and transportation | 1,233,855 | 1,233,855 | — |
| Total revenues | 2,912,770 | 2,803,341 | 109,429 |
| | | | |
| Onshore facilities and transportation product costs | 1,037,688 | 1,037,688 | — |
| Onshore facilities and transportation operating costs | 89,042 | 89,042 | — |
| Marine transportation operating costs | 172,527 | 172,527 | — |
| Sodium minerals and sulfur services operating costs | 912,491 | 808,718 | 103,773 |
| Offshore pipeline transportation operating costs | 66,668 | 66,668 | — |
| | | | |
| OPERATING INCOME | 170,248 | 164,592 | 5,656 |

The effects of changes pursuant to ASC 606 in the tables above are attributable to our offshore pipeline transportation services operating segment and our sodium minerals and sulfur services operating segment.

In our offshore pipeline transportation services segment, we have certain contracts with customers that contain tiered pricing structures that are dependent upon reaching certain cumulative milestones of throughput volumes on our pipelines. In addition, we have a contract that contains fixed and variable consideration for us to stand ready to provide firm reservation capacity for a fixed minimum quantity on our pipeline. Pursuant to the new guidance, we have allocated our estimated total transaction price over the life of the contract to the related performance obligation and recognized the effects in our Consolidated Financial Statements. In our sodium minerals and sulfur services operating segment, specifically our legacy refinery services business, we have two distinct performance obligations, including the completion of our refinery sulfur removal process, for which we receive in-kind consideration, and our sale of NaHS to our customers. As a result, we have recorded revenue and the related cost of sales in the Consolidated Financial Statements for the year ended December 31, 2018 for services performed for the in-kind consideration for our services. Further discussion of our performance obligations by type and segment are below.

Revenue from Contracts with Customers

The following table reflects the disaggregation of our revenues by major category for the year ended December 31, 2018:

| | Year Ended December 31, Onshore Facilities & Transportation | Sodium Minerals & Sulfur Services | Offshore Pipeline Transportation | Marine Transportation | Consolidated |
|---|---|---|---|---|---|
| Fee-based revenues | $156,266 | $— | $ 284,544 | $ 219,937 | $660,747 |
| Product Sales | 1,077,589 | 1,071,634 | — | — | 2,149,223 |
| Refinery Services | — | 102,800 | — | — | 102,800 |
| | $1,233,855 | $1,174,434 | $ 284,544 | $ 219,937 | $2,912,770 |

Table of Contents

The Company recognizes revenue upon the satisfaction of its performance obligations under its contracts. The timing of revenue recognition varies for the revenue streams described in more detail below. In general, the timing includes recognition of revenue over time as services are being performed as well as recognition of revenue at a point in time, for delivery of products.

Fee-based Revenues
We provide a variety of fee-based transportation and logistics services to our customers across several of our reportable segments as outlined below.

Service contracts generally contain a series of distinct services that are substantially the same and have the same pattern of transfer to the customer over the contract period, and therefore qualify as a single performance obligation that is satisfied over time. The customer receives and consumes the benefit of our services simultaneously with the provision of those services.

Offshore Pipeline Transportation
Revenue from our offshore pipelines is generally based upon a fixed fee per unit of volume (typically per Mcf of natural gas or per barrel of crude oil) gathered, transported, or processed for each volume delivered. Fees are based either on contractual arrangements or tariffs regulated by the FERC. Certain of our contracts include a single performance obligation to stand ready, on a monthly basis, to provide capacity on our assets. Revenue associated with these fee-based services is recognized as volumes are delivered over the performance obligation period.

In addition to the offshore pipeline transportation revenue discussed above, we also have certain contracts with customers in which we earn either demand-type fees or firm capacity reservation fees. These fees are charged to a customer regardless of the volume the customer actually delivers to the platform or through the pipeline.

In addition to these offshore pipeline transportation services revenue streams, we also have certain customer contracts in which the transportation fee has a tiered pricing structure based on cumulative milestones of throughput on the related pipeline asset and contract, or on a specified date. The performance obligation for these contracts is to transport, gather or process commodity volumes for the customer based on firm (stand ready) service or from monthly nominations made by our customers, which can also be on an interruptible basis. While our transportation rate changes when milestones are achieved for certain cumulative throughput, our performance obligation does not change throughout the life of the contract. Therefore revenue is recognized on an average rate basis throughout the life of the contract. We have estimated the total consideration to be received under the contract beginning at the contract inception date based on the estimated volumes (including certain minimum volumes we are required to stand ready for), price indexing, estimated production or contracted volumes, and the contract period. We have constrained the estimates of variable consideration such that it is probable that a significant reversal of previously-recognized revenue will not occur throughout the life of the contract. These estimates will be reassessed at each reporting period as required. Billings to our customers are reflected at the contract rate. The difference between the consideration received from our customers from invoicing compared to the revenue recognized creates a contract asset or liability. In circumstances where the estimated average contract rate is less than the billed current price tier in the contract, we will recognize a contract liability. In circumstances where the estimated average contract rate is higher than the billed current price tier in the contract, we will recognize a contract asset.

Onshore Facilities and Transportation
Within our onshore facilities and transportation segment, we provide our customers with pipeline transportation, terminalling services, and rail loading/unloading services, among others, primarily on a per barrel fee basis.

Revenues from contracts for the transportation of crude oil by our pipelines are based on actual volumes at a published tariff and some contain minimum throughput provisions which reset within one year. We recognize revenues for transportation and other services over the performance obligation period, which is the contract term. Revenues for both firm and interruptible transportation and other services are recognized over time as the product is delivered to the agreed upon delivery point or at the point of receipt because they specifically relate to our efforts to transfer the distinct services.

Pricing for our services is determined through a variety of mechanisms, including specified contract pricing or regulated tariff pricing. The consideration we receive under these contracts is variable, as the total volume of the commodity to be transported is unknown at contract inception. At the end of a day or month (as specified in the contract), both the price and volume are known (or “fixed”) in order to allow us to accurately calculate the amount of consideration we are entitled to invoice. The measurement of these services and invoicing occurs on a monthly basis.

Table of Contents

Pipeline Loss Allowances
To compensate us for bearing the risk of volumetric losses of crude oil in transit in our pipelines (for our onshore and offshore pipelines) due to temperature, crude quality, and the inherent difficulties of measurement of liquids in a pipeline, our tariffs and agreements allow for us to make volumetric deductions for quality and volumetric fluctuations. We refer to these deductions as pipeline loss allowances ("PLA"). We compare these allowances to the actual volumetric gains and losses of the pipeline and the net gain or loss is recorded as revenue or a reduction of revenue. As the allowance is related to our pipeline transportation services, the performance obligation is the obligation to transport and deliver the barrels and is considered a single obligation.

When net gains occur, we have crude oil inventory. When net losses occur, we reduce any recorded inventory on hand and record a liability for the purchase of crude oil required to replace the lost volumes. Under ASC 606, we record excess oil as non-cash consideration in the transaction price on a net basis. The net oil recorded is valued at the lower of cost or net realizable value using the market price of crude oil during the month the product was transported. The crude oil in inventory can then be sold at current prevailing market prices, resulting in additional revenue if the sales price exceeds the inventory value when control transfers to the customer.

Marine Transportation
Our marine transportation business consists of revenues from the inland and offshore marine transportation of heavy refined petroleum products, asphalt and crude oil, using our barges or vessels. This revenue is recognized over the passage of time of individual trips as determined on an individual contract basis. Revenue from these contracts is typically based on a set day-rate or a set fee per cargo movement. The costs of fuel and certain other operational costs may be directly reimbursed by the customer, if stipulated in the contract.

Our performance obligation consists of providing transportation services using our vessels for a single day either under a term or spot based contract. The transaction price is usually fixed per the contract either as a day rate or as a lump sum to be allocated over the days required to complete the service. Revenue is recognizable as the transportation service utilizing our vessels occurs, as the customer simultaneously receives and consumes these services as they are provided. If provided in the contract, certain items such as fuel or operational costs can be rebilled to the customer in the same period in which the costs are incurred. In the event the timing of a trip to provide our services crosses a reporting period under a lump sum fee contract, the revenue earned is accrued based on the progress completed in the current period on the related performance obligation as we are entitled to payment for each day. Customer invoicing occurs at the completion of a trip, or earlier at the customer’s request.

Product Sales
Sodium Minerals and Sulfur Services
Product sales in our sodium minerals and sulfur services segment primarily involve the sales of caustic soda, NaHS, soda ash and other alkali products. As it relates to revenue recognition, these sales transactions contain a single performance obligation, which is the delivery of the product to the customer at the agreed upon point of sale. For some transactions, control of product transfers to the customer at the shipping point, but we are obligated to arrange for shipment of the product as directed by the customer. Rather than treating these shipping activities as separate performance obligations, our policy is to account for them as fulfillment costs in accordance with ASC 606.

The transaction price for these product sales are determined by specific contracts, typically at a fixed rate or based on a market or indexed rate. This pricing is known, or is “fixed,” at the time of revenue recognition. Invoicing and related payment terms are in accordance with industry standard or contract specification based on final pricing. The entirety of the transaction price is allocated to the performance obligation, which is delivery of the product at the agreed upon point of sale. As this type of revenue is earned at a point in time, there is no allocation of transaction price to future performance obligations.

Onshore Facilities and Transportation
Product sales in our onshore facilities and transportation segment primarily involve the sales of crude oil and petroleum products. These contracts contain a single performance obligation, which is the delivery of the product to the customer at a specified location. These contracts are settled on a monthly basis for term contracts, or on a spot basis. Invoicing and related payment terms are in accordance with industry standard or contract specification based on final pricing.

Pricing is designated within the contracts and is either fixed, index-based or formulaic, utilizing an average price for the month or for a specified range of days, regardless of when delivery occurs. In either case, pricing is known at the time of invoicing. The entirety of the consideration is allocated to a single performance obligation, which is delivery of the product to a specified location. As this type of revenue is earned at a point in time, there is no allocation of transaction price to future performance obligations.

Refinery Services
Our refinery services business primarily provides sulfur extraction services to refiners' high sulfur (or "sour") gas streams that the refineries have generated from crude oil processing operations. Our process applies our proprietary technology, which uses caustic soda to act as a scrubbing agent at a prescribed temperature and pressure to remove sulfur. The technology returns a clean (sulfur-free) hydrocarbon stream to the refinery for further processing into refined products, and simultaneously produces NaHS. Units of NaHS are produced ratably as a gas stream is processed. We obtain control and ownership of the NaHS immediately upon production, which constitutes the sole consideration that we received for our sulfur removal services. We later market this product to third parties as part of our product sales, as described above. As part of some of our arrangements, we pay a refinery access fee ("RSA fee") for any benefits received by virtue of our plant's proximity to the customer's refinery. Our RSA fee is recorded as a reduction of revenue.

Providing sulfur removal services is the singular performance obligation in our refinery service agreements. As our customers simultaneously receive and consume the refinery service benefits, control is transferred and revenue is recognized over time based on the extent of progress towards completion of the performance obligations. We use units of NaHS produced during a period to measure progress as the amount we receive corresponds directly with the efforts to provide our services completed to date. The transaction price for each performance obligation is determined using the fair value of a unit of NaHS on the contract inception date for each refinery services agreement. Accordingly, we record the value of NaHS received as non-cash consideration in inventory until it is subsequently sold to our customers (see Product Sales, above).
Contract Assets and Liabilities
The table below depicts our contract asset and liability balances at January 1, 2018 and December 31, 2018:

| | Contract Assets Non-Current | Contract Liabilities Non-Current |
|---|---|---|
| Balance at January 1, 2018 | $ 59,204 | $ 19,864 |
| Balance at December 31, 2018 | 72,241 | 26,271 |

During the year ended December 31, 2018, there were no balances that were previously classified as contract liabilities at the beginning of the period that were recognized as revenues. Accounts receivable-trade, net does not include consideration received in kind from our refinery services process. We did not have any contract modifications during the period that would affect our contract asset and liability balances.

Transaction Price Allocations to Remaining Performance Obligations
We are required to disclose the amount of our transaction prices that are allocated to unsatisfied performance obligations as of December 31, 2018. However, ASC 606 provides the following practical expedients and exemptions that we utilized:

1) Performance obligations that are part of a contract with an expected duration of one year or less;

2) Revenue recognized from the satisfaction of performance obligations where we have a right to consideration in an amount that corresponds directly with the value provided to customers; and

3) Contracts that contain variable consideration, such as index-based pricing or variable volumes, that is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct good or service that is part of a series.

We apply these practical expedients and exemptions to our revenue streams recognized over time. The majority of our contracts qualify for one of these expedients or exemptions. After considering these practical expedients and identifying the remaining contract types that involve revenue recognition over a long-term period and include long-term fixed consideration (adjusted for indexing as required), we determined our allocations of transaction price that relate to unsatisfied performance obligations. As it relates to our tiered pricing offshore transportation contracts, we provide firm capacity for both fixed and variable consideration over a long term period. Therefore, we have allocated the remaining contract value (as estimated and discussed above) to future periods. In our onshore facilities and transportation segment, we have certain contractual arrangements in which we receive fixed minimum payments for our obligation to provide minimum capacity on our pipelines and related assets.

Table of Contents

The following chart depicts how we expect to recognize revenues for future periods related to these contracts:

| | Offshore Pipeline Transportation | Marine Transportation | Onshore Facilities and Transportation |
|---|---|---|---|
| 2019 | $ 74,200 | $ 27,010 | $ 65,436 |
| 2020 | 51,256 | 20,128 | 57,090 |
| 2021 | 34,562 | — | 20,139 |
| 2022 | 22,828 | — | 4,283 |
| 2023 | 12,076 | — | — |
| Thereafter | 123,371 | — | — |
| Total | $ 318,293 | $ 47,138 | $ 146,948 |

4. Acquisitions

Alkali Business

On September 1, 2017, we acquired our Alkali Business for approximately $1.325 billion (inclusive of approximately $105 million in working capital). Our Alkali Business mines and processes trona from which it produces natural soda ash, also known as sodium carbonate ($Na_2CO_3$), as basic building block for a number of ubiquitous products, including flat glass, container glass, dry detergent and a variety of chemicals and other industrial products. To finance that transaction and the related costs, we used proceeds from (i) a $550 million public offering of 6.50% senior unsecured notes due 2025 in August 2017, generating net proceeds of $540.1 million after issuance and underwriting fees, (ii) a $750 million private placement of Class A Convertible Preferred units in September 2017, generating net proceeds of $726.4 million, (iii) borrowings under our revolving credit facility and (iv) cash on hand.

We have reflected the financial results of our Alkali Business in our sodium minerals and sulfur services segment from the date of acquisition. The purchase price has been allocated to the assets acquired and liabilities assumed and the fair values were developed by management with the assistance of a third-party valuation firm. Our finalized purchase price allocation remains unchanged from what was disclosed in the financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2017.

The allocation of the purchase price, as presented on our Consolidated Balance Sheet, is summarized as follows:

| | |
|---|---|
| Accounts receivable | 138,258 |
| Inventories | 34,929 |
| Other current assets | 13,254 |
| Fixed assets | 663,217 |
| Mineral leaseholds | 566,019 |
| Intangible assets | 800 |
| Other assets | 3,612 |
| Accounts payable | (44,547) |
| Accrued Liabilities | (36,884) |
| Other long-term liabilities | (13,658) |
| Total Purchase Price | $1,325,000 |

Fixed assets identified in connection with our valuation and purchase price allocation include the related facilities, machinery and equipment associated with our Alkali Business, principally at our Green River, Wyoming operations. These assets will be depreciated under the straight line method and have useful lives ranging from 2 to 30 years. Mineral leaseholds include the trona reserves at our Green River, Wyoming facility and are depleted over their useful lives as determined by the units of production method. Other long-term liabilities contains various items including assumed employee benefit plan obligations. Other items principally consist of working capital items of our Alkali Business as acquired on September 1, 2017.

F-19

Table of Contents

Our Consolidated Financial Statements include the results of our Alkali Business since September 1, 2017, the closing date of the acquisition. The following table presents selected financial information included in our Consolidated Financial Statements for the periods presented:

| | Year Ended December 31, 2017 |
|---|---|
| Revenues | 277,011 |
| Net income | 42,014 |

The table below presents selected unaudited pro forma financial information incorporating the historical results of our Alkali Business. The pro forma financial information below has been prepared as if the acquisition had been completed on January 1, 2016 and is based upon assumptions deemed appropriate by us and may not be indicative of actual results. This pro forma information was prepared using historical financial data of our trona and trona-based exploring, mining, processing, producing, marketing and selling business and reflects certain estimates and assumptions made by our management. Our unaudited pro forma financial information is not necessarily indicative of what our consolidated financial results would have been had our Alkali Business acquisition been completed on January 1, 2016. Pro forma net income includes the effects of distributions on preferred units and interest expense on incremental borrowings. The dilutive effect of our Class A Convertible Preferred Units is calculated using the if-converted method.

| | Year Ended December 31, | |
|---|---|---|
| | 2017 | 2016 |
| Pro forma consolidated financial operating results: | | |
| Revenues | $2,549,438 | $2,498,293 |
| Net Income Attributable to Genesis Energy, L.P. | 108,392 | 156,700 |
| Net Income Available to Common Unitholders | 42,768 | 91,076 |
| Basic and diluted earnings per common unit: | | |
| As reported net income per common unit | $0.50 | $1.00 |
| Pro forma net income per common unit, basic and dilutive | $0.35 | $0.80 |

As relating to our Alkali Business acquisition, we incurred approximately $12.0 million in acquisition related costs through December 31, 2017, and incurred an additional $2.0 million during the year ended December 31, 2018. Such costs are included as "General and Administrative costs" on our Consolidated Statement of Operations.

## 5. Receivables

Accounts receivable – trade, net consisted of the following:

| | December 31, | |
|---|---|---|
| | 2018 | 2017 |
| Accounts receivable - trade | $330,855 | $503,917 |
| Allowance for doubtful accounts | (7,393 ) | (8,468 ) |
| Accounts receivable - trade, net | $323,462 | $495,449 |

Table of Contents

The following table presents the activity of our allowance for doubtful accounts for the periods indicated:

| | December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Balance at beginning of period | $8,468 | $6,505 | $1,446 |
| Charged to costs and expenses, net of recoveries | 31 | 2,001 | 6,463 |
| Amounts written off | (1,106 ) | (38 ) | (1,404 ) |
| Balance at end of period | $7,393 | $8,468 | $6,505 |

6. Inventories

The major components of inventories were as follows:

| | December 31, | |
|---|---|---|
| | 2018 | 2017 |
| Petroleum products | $12,203 | $8,731 |
| Crude oil | 8,379 | 29,873 |
| Caustic soda | 10,372 | 5,755 |
| NaHS | 12,400 | 8,277 |
| Raw materials - Alkali Operations | 5,952 | 4,550 |
| Work-in-process - Alkali Operations | 2,322 | 7,355 |
| Finished goods, net - Alkali Operations | 11,402 | 14,075 |
| Materials and supplies, net - Alkali Operations | 10,490 | 10,030 |
| Other | 11 | 7 |
| Total | $73,531 | $88,653 |

Inventories are valued at the lower of cost or net realizable value. The net realizable value of inventories were recorded below cost by approximately $1.0 million as of December 31, 2018 and were not recorded below cost as of December 31, 2017; therefore we reduced the value of inventory in our Consolidated Financial Statements for this difference.

Materials and supplies include chemicals, maintenance supplies, and spare parts which will be consumed in the mining of trona ore and production of soda ash processes.

Table of Contents

7. Fixed Assets, Mineral Leaseholds and Asset Retirement Obligations
Fixed Assets
Fixed assets consisted of the following:

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| Crude oil pipelines and natural gas pipelines and related assets | $2,918,285 | $3,028,657 |
| Alkali facilities, machinery, and equipment | 533,924 | 497,601 |
| Onshore facilities, machinery, and equipment | 639,023 | 692,364 |
| Transportation equipment | 20,102 | 21,483 |
| Marine vessels | 951,597 | 918,953 |
| Land, buildings and improvements | 222,242 | 223,186 |
| Office equipment, furniture and fixtures | 20,505 | 18,112 |
| Construction in progress | 94,025 | 151,768 |
| Other | 41,155 | 48,891 |
| Fixed assets, at cost | 5,440,858 | 5,601,015 |
| Less: Accumulated depreciation | (1,023,825 ) | (734,986 ) |
| Net fixed assets | $4,417,033 | $4,866,029 |

Mineral Leaseholds
Our Mineral Leaseholds, relating to our acquired Alkali Business, consist of the following:

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| Mineral leaseholds | 566,019 | 566,019 |
| Less: Accumulated depletion | (5,538 ) | (1,513 ) |
| Mineral leaseholds, net | $ 560,481 | $ 564,506 |

Depreciation expense was $286.0 million, $226.0 million and $194.0 million for the years ended December 31, 2018, 2017, and 2016, respectively. Depletion expense was $4.0 million and $1.5 million for the years ended December 31, 2018 and 2017, respectively.

On October 11, 2018, we completed the divestiture of our Powder River Basin midstream assets, included in our Onshore Facilities and Transportation segment, and received total net proceeds of approximately $300 million. This sale resulted in a gain of $38.9 million recorded in Gains on assets sales in the Consolidated Statements of Operations. Additionally, we recorded an impairment expense of $21.2 million on our remaining non-core midstream assets in the Powder River Basin as the carrying value exceeded the fair value in the current market at December 31, 2018.

During 2018, we also recorded impairment expense of $82.0 million associated with certain of our non-core offshore gas assets in the Gulf of Mexico due to a change in contractual arrangements during the fourth quarter. Included in this amount is the acceleration in timing of the abandonment of one of our offshore hub platforms and pipelines and the write-off of its associated asset retirement obligation assets. The fair value of our assets was determined based on present value techniques.

During 2017, we sold certain non-core natural gas gathering and platform assets in the Gulf of Mexico included in our offshore pipeline transportation services segment, as well as certain onshore terminal facilities in West Texas included in our onshore facilities and transportation segment. These sales resulted in total gains on asset sales of $40.3 million for the year ended December 31, 2017 recorded in Gains on assets sales in the Consolidated Statements of Operations.

Table of Contents

Asset Retirement Obligations

We record AROs in connection with legal requirements to perform specified retirement activities under contractual arrangements and/or governmental regulations. For any AROs acquired, we record AROs based on the fair value measurement assigned during the preliminary purchase price allocation.

A reconciliation of our liability for asset retirement obligations is as follows:

| | |
|---|---|
| December 31, 2016 | $213,726 |
| Accretion expense | 11,008 |
| Revisions in timing and estimated costs of AROs | 7,146 |
| Acquisitions | 131 |
| Divestitures | (7,649 ) |
| Settlements | (26,415 ) |
| Other | 240 |
| December 31, 2017 | 198,187 |
| Accretion expense | 10,509 |
| Revisions in timing and estimated costs of AROs | 44,319 |
| Settlements | (13,150 ) |
| December 31, 2018 | $239,865 |

At December 31, 2018 and December 31, 2017, $67.5 million and $20.9 million are included as current in "Accrued liabilities" on our Consolidated Balance Sheet, respectively. Revisions in timing and estimated costs during 2018 is primarily attributable to the accelerated timing and revised costs associated with the abandonment of certain of our non-core offshore gas assets in the Gulf of Mexico. The remainder of the ARO liability at each period is included in "Other long-term liabilities" on our Consolidated Balance Sheet.

With respect to our AROs, the following table presents our forecast of accretion expense for the periods indicated:

| | |
|---|---|
| 2019 | $9,928 |
| 2020 | $10,997 |
| 2021 | $9,313 |
| 2022 | $9,892 |
| 2023 | $10,586 |

Certain of our unconsolidated affiliates have AROs recorded at December 31, 2018 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our Consolidated Financial Statements.

8. Net Investment in Direct Financing Leases

Our direct financing leases include a lease of the Northeast Jackson Dome (“NEJD”) Pipeline. Under the terms of the agreement, we are paid quarterly payments, which commenced August 2008. These quarterly payments are fixed at approximately $20.7 million per year during the lease term at an interest rate of 10.25%. At the end of the lease term in 2028, we will convey all of our interests in the NEJD Pipeline to the lessee for a nominal payment. There are requirements in our leases that would provide credit support should the credit rating of our lessee fall to certain levels, and at December 31, 2018, the required credit support has been provided.

Table of Contents

The following table lists the components of the net investment in direct financing leases:

| | December 31, | |
|---|---|---|
| | 2018 | 2017 |
| Total minimum lease payments to be received | $195,280 | $215,884 |
| Unamortized initial direct costs | 801 | 950 |
| Less unearned income | (70,735 ) | (83,918 ) |
| Net investment in direct financing leases | 125,346 | 132,916 |
| Less current portion (included in other current assets) | (8,421 ) | (7,633 ) |
| Long-term portion of net investment in direct financing leases | $116,925 | $125,283 |

At December 31, 2018, minimum lease payments to be received for each of the five succeeding fiscal years are $20.7 million.

9. Equity Investees

We account for our ownership in our joint ventures under the equity method of accounting (see Note 2 for a description of these investments). The price we pay to acquire an ownership interest in a company may exceed or be less than the underlying book value of the capital accounts we acquire. At December 31, 2018 and 2017, the unamortized differences in carrying value totaled $366.4 million and $382.4 million, respectively. We amortize the differences in carrying value as a change in equity earnings.

In the first quarter of 2016, we purchased the remaining 50% interest in Deepwater Gateway, LLC for approximately $26.0 million (including adjustments for working capital), increasing our ownership interest to 100%. Consequently, we now consolidate Deepwater Gateway, LLC instead of accounting for our interest under the equity method.

The following table presents information included in our Consolidated Financial Statements related to our equity investees.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Genesis’ share of operating earnings | $59,255 | $66,814 | $63,805 |
| Amortization of differences attributable to Genesis' carrying value of equity investments | (15,629 ) | (15,768 ) | (15,861 ) |
| Net equity in earnings | $43,626 | $51,046 | $47,944 |
| Distributions received | $71,714 | $82,898 | $87,220 |

Table of Contents

The following tables present the combined balance sheet information for the last two years and income statement data for the last three years for our equity investees (on a 100% basis) including the effects of the change in our ownership interest due to the Deepwater acquisition as previously discussed:

| | December 31, | |
|---|---|---|
| | 2018 | 2017 |
| BALANCE SHEET DATA: | | |
| Assets | | |
| Current assets | $34,005 | $34,381 |
| Fixed assets, net | 346,864 | 362,214 |
| Other assets | 15,469 | 14,927 |
| Total assets | $396,338 | $411,522 |
| Liabilities and equity | | |
| Current liabilities | $18,897 | $23,289 |
| Other liabilities | 250,742 | 249,610 |
| Equity | 126,699 | 138,623 |
| Total liabilities and equity | $396,338 | $411,522 |

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| INCOME STATEMENT DATA: | | | |
| Revenues | $180,056 | $191,078 | $193,038 |
| Operating Income | $129,160 | $139,604 | $122,836 |
| Net Income | $115,669 | $134,479 | $118,175 |

Poseidon's revolving credit facility

Borrowings under Poseidon’s revolving credit facilities, which was amended and restated in February 2015, are primarily used to fund spending on capital projects. The February 2015 credit facility is non-recourse to Poseidon’s owners and secured by its assets. The February 2015 credit facility contains customary covenants such as restrictions on debt levels, liens, guarantees, mergers, sale of assets and distributions to owners. A breach of any of these covenants could result in acceleration of the maturity date of Poseidon’s debt. Poseidon was in compliance with the terms of its credit agreement for all periods presented in these consolidated financial statements.

Table of Contents

10. Intangible Assets, Goodwill and Other Assets
Intangible Assets
The following table reflects the components of intangible assets being amortized at December 31, 2018 and 2017:

| | | December 31, 2018 | | | December 31, 2017 | | |
|---|---|---|---|---|---|---|---|
| | Weighted Amortization Period in Years | Gross Carrying Amount | Accumulated Amortization | Carrying Value | Gross Carrying Amount | Accumulated Amortization | Carrying Value |
| Sodium Minerals and Sulfur Services: | | | | | | | |
| Customer relationships | 5 | $94,654 | $ 94,654 | $— | $94,654 | $ 92,493 | $2,161 |
| Licensing agreements | 6 | 38,678 | 38,678 | — | 38,678 | 36,528 | 2,150 |
| Non-compete agreement | 3 | 800 | 356 | 444 | 800 | 89 | 711 |
| Segment total | | 134,132 | 133,688 | 444 | 134,132 | 129,110 | 5,022 |
| Onshore Facilities & Transportation: | | | | | | | |
| Customer relationships | 5 | 35,430 | 35,123 | 307 | 35,430 | 35,082 | 348 |
| Intangibles associated with lease | 15 | 13,260 | 5,407 | 7,853 | 13,260 | 4,933 | 8,327 |
| Segment total | | 48,690 | 40,530 | 8,160 | 48,690 | 40,015 | 8,675 |
| Marine contract intangible | 5 | 27,000 | 17,100 | 9,900 | 27,000 | 11,700 | 15,300 |
| Offshore pipeline contract intangibles | 19 | 158,101 | 28,431 | 129,670 | 158,101 | 20,109 | 137,992 |
| Other | 5 | 30,947 | 16,519 | 14,428 | 28,900 | 13,483 | 15,417 |
| Total | | $398,870 | $ 236,268 | $162,602 | $396,823 | $ 214,417 | $182,406 |

The licensing agreements referred to in the table above relate to the agreements we have with refiners to provide services. The onshore facilities and transportation lease relates to a terminal facility in Shreveport, Louisiana. The marine contract intangible relates to the contracts we assumed in the purchase of the M/T American Phoenix in November 2014.

The offshore pipeline contract intangibles relate to customer contracts surrounding certain transportation agreements with producers in the Lucius production area in Southeast Keathley Canyon, which support our SEKCO pipeline identified in connection with our purchase price allocation surrounding the Enterprise Acquisition.

We are recording amortization of our intangible assets based on the period over which the asset is expected to contribute to our future cash flows. Generally, the contribution to our cash flows of the customer and supplier relationships, licensing agreements and trade name intangible assets is expected to decline over time, such that greater value is attributable to the periods shortly after the acquisition was made. The onshore facilities and transportation lease, marine contract, offshore pipeline contract intangibles and other intangible assets are being amortized on a straight-line basis. Amortization expense on intangible assets was $21.8 million, $23.6 million and $24.3 million for the years ended December 31, 2018, 2017 and 2016, respectively.

The following table reflects our estimated amortization expense for each of the five subsequent fiscal years:

| | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|
| Sodium Minerals and Sulfur Services: | | | | | |
| Non Compete | 267 | 177 | — | — | — |
| Onshore Facilities & Transportation: | | | | | |
| Customer relationships | 39 | 38 | 37 | 35 | 34 |
| Intangibles associated with lease | 474 | 474 | 474 | 474 | 474 |
| Marine contract intangibles | 5,400 | 4,500 | — | — | — |
| Offshore pipeline contract intangibles | 8,321 | 8,321 | 8,321 | 8,321 | 8,321 |
| Other | 3,153 | 3,132 | 2,011 | 1,853 | 1,568 |

| | | | | | |
|---|---|---|---|---|---|
| Total | $17,654 | $16,642 | $10,843 | $10,683 | $10,397 |

Table of Contents

Goodwill

The carrying amount of goodwill in sodium minerals and sulfur services was $301.9 million in December 31, 2018 and 2017. During 2018, we recognized a goodwill impairment loss of $23.1 million related to our onshore facilities and transportation segment during the period. The goodwill impairment was specifically related to our supply and logistics reporting unit, that primarily includes our legacy crude oil and refined products marketing and trucking businesses. Due to our efforts to rightsize these businesses, along with the volatility of crude oil prices and the impact this volatility has on the availability of crude oil and heavy refined products for us to market, the fair value of the reporting unit was determined to be lower than the carrying value of the reporting unit, including goodwill. The fair value was derived using a discounted cash flow present value technique.

Other Assets

Other assets consisted of the following:

| | December 31, | |
|---|---|---|
| | 2018 | 2017 |
| $CO_2$ volumetric production payments, net of amortization | $890 | $2,175 |
| Deferred marine charges, net [(1)] | 28,175 | 30,246 |
| Contract assets [(2)] | 72,241 | — |
| Other deferred costs and deposits | 20,401 | 24,207 |
| Other assets, net of amortization | $121,707 | $56,628 |

(1) See discussion of deferred charges on marine transportation assets in the Summary of Accounting Policies (Note 2)

(2) See Revenue Recognition (Note 3) for discussion on the circumstances that result in the recognition of contract assets.

The $CO_2$ assets are being amortized on a units-of-production method. We recorded amortization of $1.3 million in 2018, $1.3 million in 2017 and $3.9 million in 2016.

11. Debt

At December 31, 2018 and 2017, our obligations under debt arrangements consisted of the following:

| | December 31, 2018 | | | December 31, 2017 | | |
|---|---|---|---|---|---|---|
| | Principal | Unamortized Discount and Debt Issuance Costs [(1)] | Net Value | Principal | Unamortized Discount and Debt Issuance Costs [(1)] | Net Value |
| Senior secured credit facility | $970,100 | $ — | $970,100 | $1,099,200 | $ — | 1,099,200 |
| 5.750% senior unsecured notes | — | — | — | 145,170 | 1,303 | 143,867 |
| 6.750% senior unsecured notes | 750,000 | 12,763 | 737,237 | 750,000 | 16,077 | 733,923 |
| 6.000% senior unsecured notes | 400,000 | 4,624 | 395,376 | 400,000 | 5,691 | 394,309 |
| 5.625% senior unsecured notes | 350,000 | 4,820 | 345,180 | 350,000 | 5,717 | 344,283 |
| 6.500% senior unsecured notes | 550,000 | 8,241 | 541,759 | 550,000 | 9,462 | 540,538 |
| 6.250% senior unsecured notes | 450,000 | $ 7,189 | 442,811 | 450,000 | 8,002 | 441,998 |
| Total long-term debt | $3,470,100 | $ 37,637 | $3,432,463 | $3,744,370 | $ 46,252 | $3,698,118 |

(1) Unamortized debt issuance costs associated with our senior secured credit facility (included in Other Long Term Assets on the Consolidated Balance Sheet) were $10.8 million and $14.1 million as of December 31, 2018 and December 31, 2017, respectively.

Senior Secured Credit Facility

In October 2018, we amended our credit agreement to, among other things, make certain technical amendments related to the sale of our Powder River Basin midstream assets. The key terms for rates under our $1.7 billion senior secured credit facility, which are dependent on our leverage ratio (as defined in the credit agreement), are as follows:

- The interest rate on borrowings may be based on an alternate base rate or a Eurodollar rate, at our option. The alternate base rate is equal to the sum of (a) the greatest of (i) the prime rate as established by the administrative agent for the credit facility, (ii) the federal funds effective rate plus 0.5% of 1% and (iii) the LIBOR rate for a one-month maturity plus 1% and (b) the applicable margin. The Eurodollar rate is equal to the sum of (a) the LIBOR rate for the applicable interest period multiplied by the statutory reserve rate and (b) the applicable margin. The applicable margin varies from 1.50% to 3.00% on Eurodollar borrowings and from 0.50% to 2.00% on alternate base rate borrowings, depending on our leverage ratio. Our leverage ratio is recalculated quarterly and in connection with each material acquisition. At December 31, 2018, the applicable margins on our borrowings were 1.75% for alternate base rate borrowings and 2.75% for Eurodollar rate borrowings.

- Letter of credit fees range from 1.50% to 3.00% based on our leverage ratio as computed under the credit facility. The rate can fluctuate quarterly. At December 31, 2018, our letter of credit rate was 2.75%.
- We pay a commitment fee on the unused portion of the $1.7 billion maximum facility amount. The commitment fee on the unused committed amount will range from 0.25% to 0.50% per annum depending on our leverage ratio (0.50% at December 31, 2018).
- Our credit facility contains a $300 million accordion feature, giving us the ability to expand the size of the facility up to $2.0 billion for acquisitions or growth projects, subject to lender consent.

Our credit facility contains customary covenants (affirmative, negative and financial) that could limit the manner in which we may conduct our business. As defined in our credit facility, we are required to meet three primary financial metrics—a maximum leverage ratio, a maximum senior secured leverage ratio and a minimum interest coverage ratio. Our credit agreement provides for the temporary inclusion of certain pro forma adjustments to the calculations of the required ratios following material acquisitions. In general, our leverage ratio calculation compares our consolidated funded debt (including outstanding notes we have issued) to EBITDA (as defined and adjusted in accordance with the credit facility) and cannot exceed 5.50 to 1.00. Our senior secured leverage ratio excludes outstanding debt under senior unsecured notes and cannot exceed 3.75 to 1.00. Our interest coverage ratio calculation compares EBITDA (as defined and adjusted in accordance with the credit facility) to interest expense and must be greater than 3.00 to 1.00 (2.75 to 1.00 during an acquisition period).

At December 31, 2018, we had $970.1 million borrowed under our credit facility, with $17.8 million of the borrowed amount designated as a loan under the inventory sublimit. Our credit agreement allows up to $100 million of the capacity to be used for letters of credit, of which $1.2 million was outstanding at December 31, 2018. Due to the revolving nature of loans under our credit facility, additional borrowings and periodic repayments and re-borrowings may be made until the maturity date of May 9, 2022. The total amount available for borrowings under our credit facility at December 31, 2018 was $728.7 million. Our credit facility does not include a “borrowing base” limitation except with respect to our inventory loans.

Senior Unsecured Notes

On February 8, 2013, we issued $350 million of aggregate principal amount of 5.75% senior unsecured notes due February 15, 2021 (the "2021 Notes"). On December 11, 2017, $204.8 million of these notes were validly tendered and repaid upon the issuance of our $450 million unsecured notes issued on December 11, 2017 as discussed below. A total loss of approximately $6.2 million for the tender is recorded to "Other income/(expense), net" in our Consolidated Statements of Operations as of December 31, 2017. On February 15, 2018, we redeemed our remaining 2021 Notes in full at a redemption price of 101.438% of the principal amount, plus accrued and unpaid interest up to, but not including, the redemption date. We incurred a total loss of approximately $3.3 million relating to the extinguishment of those notes (including the write-off of the related unamortized debt issuance costs), which loss is recorded as "Other income/(expense), net" in our Consolidated Statements of Operations for the year ended December 31, 2018.

On May 15, 2014, we issued $350 million in aggregate principal amount of 5.625% senior unsecured notes due December 15, 2024 (the "2024 Notes"). Our 2024 Notes were sold at face value. Interest payments are due on June 15 and December 15 of each year with the initial interest payment due December 15, 2014. Our 2024 Notes mature on June 15, 2024. The net proceeds were used to repay borrowings under our credit facility and for general partnership purposes.

On May 21, 2015, we issued $400 million in aggregate principal amount of 6.00% senior unsecured notes due May 15, 2023 (the "2023 Notes"). Interest payments are due on May 15 and November 15 of each year with the initial interest payment due November 15, 2015. Our 2023 Notes mature on May 15, 2023. We used a portion of the proceeds from those notes to effectively redeem all of our outstanding $350 million, 7.875% senior unsecured notes due 2018, using a combination of public tender offer and our redemption rights relating to those notes.

On July 23, 2015, we issued $750 million in aggregate principal amount of 6.75% senior unsecured notes due August 1, 2022 (the "2022 Notes"). Interest payments are due on February 1 and August 1 of each year with the initial interest payment due February 1, 2016. Our 2022 Notes mature on August 1, 2022. That issuance generated net proceeds of $728.6 million net of issuance discount and underwriting fees. The net proceeds were used to fund a portion of the purchase price for our Enterprise acquisition.

Table of Contents

On August 14, 2017, we issued $550 million in aggregate principal amount of 6.50% senior unsecured notes due October 1, 2025 (the "2025 Notes"). Interest payments are due April 1 and October 1 of each year with the initial interest payment due April 1, 2018. That issuance generated net proceeds of $540.1 million, net of issuance costs incurred. Our 2025 Notes mature on October 1, 2025. The net proceeds were used to fund a portion of the purchase price for our acquisition of our Alkali Business.

On December 11, 2017, we issued $450 million in aggregate principal amount of 6.25% senior unsecured notes due May 15, 2026 (the "2026 Notes"). Interest payments are due May 15 and November 15 of each year with the initial interest payment due May 15, 2018. That issuance generated net proceeds of $441.8 million, net of issuance costs incurred. We used $204.8 million of the net proceeds to redeem the portion of the 5.75% senior unsecured notes due February 15, 2021 (the "2021 Notes") that were validly tendered and the remaining net proceeds to repay a portion of the borrowings outstanding under our revolving credit facility.

We have the right to redeem each of our series of notes beginning on specified dates as summarized below, at a premium to the face amount of such notes that varies based on the time remaining to maturity on such notes. Additionally, we may redeem up to 35% of the principal amount of each of our series of notes with the proceeds from an equity offering of our common units during certain periods. A summary of the applicable redemption periods is provided in the table below.

| | 2022 Notes | 2023 Notes | 2024 Notes | 2025 Notes | 2026 Notes |
|---|---|---|---|---|---|
| Redemption right beginning on | August 1, 2018 | May 15, 2018 | June 15, 2019 | October 1, 2020 | February 15, 2021 |
| Redemption of up to 35% of the principal amount of notes with the proceeds of an equity offering permitted prior to | August 1, 2018 | May 15, 2018 | June 15, 2019 | October 1, 2020 | February 15, 2021 |

Guarantees of our 2022, 2023, 2024, 2025 and 2026 Notes will be released under certain circumstances, including (i) in connection with any sale or other disposition of (a) all or substantially all of the properties or assets of a guarantor (including by way of merger or consolidation) or (b) all of the capital stock of such guarantor, in each case, to a person that is not a restricted subsidiary of the Partnership (ii) if the Partnership designates any restricted subsidiary that is a guarantor as an unrestricted subsidiary, (iii) upon legal defeasance, covenant defeasance or satisfaction and discharge of the applicable indenture, (iv) upon the liquidation or dissolution of such guarantor, or (v) at such time as such guarantor ceases to guarantee any other indebtedness of either of the issuers and any other guarantor.

Covenants and Compliance

Our credit agreement and the indenture governing the senior notes contain cross-default provisions. Our credit documents prohibit distributions on, or purchases or redemptions of, units if any default or event of default is continuing. In addition, those agreements contain various covenants limiting our ability to, among other things:

- incur indebtedness if certain financial ratios are not maintained;
- grant liens;
- engage in sale-leaseback transactions; and
- sell substantially all of our assets or enter into a merger or consolidation.

A default under our credit documents would permit the lenders thereunder to accelerate the maturity of the outstanding debt. As long as we are in compliance with our credit facility, our ability to make distributions of “available cash” is not restricted. As of December 31, 2018, we were in compliance with the financial covenants contained in our credit facility and indenture.

12. Partners’ Capital, Mezzanine Equity and Distributions

At December 31, 2018, our outstanding equity consisted of 122,539,221 Class A common units and 39,997 Class B common units. The Class A units are traditional common units in us. The Class B units are identical to the Class A units and, accordingly, have voting and distribution rights equivalent to those of the Class A units, and, in addition, the Class B units have the right to elect all of our board of directors and are convertible into Class A units under certain circumstances, subject to certain exceptions.

Distributions

Generally, we will distribute 100% of our available cash (as defined by our partnership agreement) within 45 days after the end of each quarter to unitholders of record. Available cash generally means, for each fiscal quarter, all cash on hand at the end of the quarter:

- less the amount of cash reserves that our general partner determines in its reasonable discretion is necessary or appropriate to:
- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments, or other agreements; or
- provide funds for distributions to our unitholders for any one or more of the next four quarters;
- plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings. Working capital borrowings are generally borrowings that are made under our credit facility and in all cases are used solely for working capital purposes or to pay distributions to partners.

We paid distributions in 2019, 2018 and 2017 as follows:

| Distribution For | Date Paid | Per Unit Amount | Total Amount |
|---|---|---|---|
| 2016 | | | |
| 4th Quarter | February 14, 2017 | $0.7100 | $83,765 |
| 2017 | | | |
| 1st Quarter | May 15, 2017 | $0.7200 | $88,257 |
| 2nd Quarter | August 14, 2017 | $0.7225 | $88,563 |
| 3rd Quarter | November 14, 2017 | $0.5000 | $61,290 |
| 4th Quarter | February 14, 2018 | $0.5100 | $62,515 |
| 2018 | | | |
| 1st Quarter | May 15, 2018 | $0.5200 | $63,741 |
| 2nd Quarter | August 14, 2018 | $0.5300 | $64,967 |
| 3rd Quarter | November 14, 2018 | $0.5400 | $66,193 |
| 4th Quarter | February 14, 2019 | $0.5500 | $67,419 |

Equity Issuances and Contributions

Our partnership agreement authorizes our general partner to cause us to issue additional limited partner interests and other equity securities, the proceeds from which could be used to provide additional funds for acquisitions or other needs.

On March 24, 2017, we issued 4,600,000 Class A common units in a public offering at a price of $30.65 per unit, which included the exercise by the underwriters of an option to purchase up to 600,000 additional common units from us. We received proceeds, net of offering costs, of approximately $140.5 million from that offering.

On July 27, 2016, we issued 8,000,000 Class A common units in a public offering at a price of $37.90 per unit. We received proceeds, net of underwriting discounts and offering costs, of approximately $298.5 million from that offering. We used those proceeds to repay a portion of the borrowings outstanding under our credit facility.

The new common units issued in 2017 and 2016 to the public for cash were as follows:

| Period | Purchaser of Common Units | Units | Gross Unit Price | Issuance Value | Costs | Net Proceeds |
|---|---|---|---|---|---|---|
| March 2017 | Public | 4,600 | $ 30.65 | $140,990 | $(477 ) | $140,513 |
| July 2016 | Public | 8,000 | $ 37.90 | $303,200 | $(4,748) | $298,452 |

Class A Convertible Preferred Units
On September 1, 2017, we sold $750 million of Class A convertible preferred units ("preferred units") in a private placement, comprised of 22,249,494 units for a cash purchase price per unit of $33.71 (subject to certain adjustments, the “Issue Price”) to two initial purchasers. Our general partner executed an amendment to our partnership agreement in connection therewith, which, among other things, authorized and established the rights and preferences of our preferred units. Our preferred units are a new class of security that ranks senior to all of our currently outstanding classes or series of limited partner interests with respect to distribution and/or liquidation rights. Holders of our preferred units vote on an as-converted basis with holders of our common units and have certain class voting rights, including with respect to any amendment to the partnership agreement that would adversely affect the rights, preferences or privileges, or otherwise modify the terms, of those preferred units.
Each of our preferred units accumulate quarterly distribution amounts in arrears at an annual rate of 8.75% (or $2.9496), yielding a quarterly rate of 2.1875% (or $0.7374), subject to certain adjustments. With respect to any quarter ending on or prior to March 1, 2019, we have the option to pay to the holders of our preferred units the applicable distribution amount in cash, preferred units, or any combination thereof. If we elect to pay all or any portion of a quarterly distribution amount in preferred units, the number of such preferred units will equal the product of (i) the number of then outstanding preferred units and (ii) the quarterly rate. We have elected to pay all distributions from inception through the quarter ending December 31, 2018 with additional preferred units. For each quarter ending after March 1, 2019, we must pay all distribution amounts in respect of our preferred units in cash.
From time to time after September 1, 2020, we will have the right to cause the conversion of all or a portion of outstanding preferred units into our common units, subject to certain conditions; provided, however, that we will not be permitted to convert more than 7,416,498 of our preferred units in any consecutive twelve-month period. At any time after September 1, 2020, if we have fewer than 592,768 of our preferred units outstanding, we will have the right to convert each outstanding preferred unit into our common units at a conversion rate equal to the greater of (i) the then-applicable conversion rate and (ii) the quotient of (a) the Issue Price and (b) 95% of the volume-weighted average price of our common units for the 30-trading day period ending prior to the date that we notify the holders of our outstanding preferred units of such conversion.
Upon certain events involving certain changes of control in which more than 90% of the consideration payable to the holders of our common units is payable in cash, our preferred units will automatically convert into common units at a conversion ratio equal to the greater of (a) the then applicable conversion rate and (b) the quotient of (i) the product of (A) the sum of (1) the Issue Price and (2) any accrued and accumulated but unpaid distributions on our preferred units, and (B) a premium factor (ranging from 115% to 101% depending on when such transaction occurs) plus a prorated portion of unpaid partial distributions, and (ii) the volume weighted average price of the common units for the 30 trading days prior to the execution of definitive documentation relating to such change of control.
In connection with other change of control events that do not meet the 90% cash consideration threshold described above, each holder of our preferred units may elect to (a) convert all of its preferred units into our common units at the then applicable conversion rate, (b) if we are not the surviving entity (or if we are the surviving entity, but our common units will cease to be listed), require us to use commercially reasonable efforts to cause the surviving entity in any such transaction to issue a substantially equivalent security (or if we are unable to cause such substantially equivalent securities to be issued, to convert its preferred units into common units in accordance with clause (a) above or exchanged in accordance with clause (d) below or convert at a specified conversion rate), (c) if we are the surviving entity, continue to hold our preferred units or (d) require us to exchange our preferred units for cash or, if we so elect, our common units valued at 95% of the volume-weighted average price of our common units for the 30 consecutive trading days ending on the fifth trading day immediately preceding the closing date of such change of control, at a price per unit equal to the sum of (i) the product of (x) 101% and (y) the Issue Price plus (ii) accrued and accumulated but unpaid distributions and (iii) a prorated portion of unpaid partial distributions.
For a period of 30 days following (i) September 1, 2022 and (ii) each subsequent anniversary thereof, the holders of our preferred units may make a one-time election to reset the quarterly distribution amount (a “Rate Reset Election”) to a cash amount per preferred unit equal to the amount that would be payable per quarter if a preferred unit accrued interest on the Issue Price at an annualized rate equal to three-month LIBOR plus 750 basis points; provided, however,

that such reset rate shall be equal to 10.75% if (i) such alternative rate is higher than the LIBOR-based rate and (ii) the then market price for our common units is then less than 110% of the Issue Price. To become effective, the Rate Reset Election requires approval of holders of at least a majority of our then outstanding preferred units and such majority must include each of our initial purchasers (or any affiliate to whom they have transferred their preferred units) if such initial purchaser (including its affiliates) holds at least 25% of the then outstanding preferred units.

Upon the occurrence of a Rate Reset Election, we may redeem our preferred units for cash, in whole or in part (subject to certain minimum value limitations) for an amount per preferred unit equal to such preferred unit's liquidation value (equal to the Issue Price plus any accrued and accumulated but unpaid distributions, plus a prorated portion of certain unpaid partial distributions in respect of the immediately preceding quarter and the current quarter) multiplied by (i) 110%, prior to

Table of Contents

September 1, 2024, and (ii) 105% thereafter. Each holder of our preferred units may elect to convert all or any portion of its preferred units into common units initially on a one-for-one basis (subject to customary adjustments and an adjustment for accrued and accumulated but unpaid distributions and limitations) at any time after September 1, 2019 (or earlier upon a change of control, liquidation, dissolution or winding up), provided that any conversion is for at least $50 million or such lesser amount if such conversion relates to all of a holder's remaining preferred units or has otherwise been approved by us.

If we fail to pay in full any preferred unit distribution amount after March 1, 2019 in respect of any two quarters, whether or not consecutive, then until we pay such distributions in full, we will not be permitted to (a) declare or make any distributions (subject to a limited exceptions for pro rata distributions on our preferred units and parity securities), redemptions or repurchases of any of our limited partner interests that rank junior to or pari passu with our preferred units with respect to rights upon distribution and/or liquidation (including our common units), or (b) issue any such junior or parity securities. If we fail to pay in full any preferred unit distribution after March 1, 2019 in respect of any two quarters, whether or not consecutive, then the preferred unit distribution amount will be reset to a cash amount per preferred unit equal to the amount that would be payable per quarter if a preferred unit accrued interest on the Issue Price at an annualized rate equal to the then-current annualized distribution rate plus 200 basis points until such default is cured.

In addition to their right to veto a Rate Reset Election under certain circumstances, we have granted each initial purchaser (including its applicable affiliate transferees) certain rights, including (i) the right to appoint an observer, who shall have the right to attend our board meetings for so long as an initial purchaser (including its affiliates) owns at least $200 million of our preferred units; (ii) the right to purchase up to 50% of any parity securities on substantially the same terms offered to other purchasers for so long as an initial purchaser (including its affiliates) owns at least 11,124,747 of our preferred units, and (iii) the right to appoint two directors to our general partner's board of directors if (and so long as) we fail to pay in full any three quarterly distribution amounts, whether or not consecutive, attributable to any quarter ending after March 1, 2019.

The Rate Reset Election of these preferred units represents an embedded derivative that must be bifurcated from the related host contract and recorded at fair value on our Consolidated Balance Sheet. See further information in Note 19. The preferred units themselves are classified as mezzanine capital on our Consolidated Balance Sheet.

Accounting for the Class A Convertible Preferred Units

Our preferred units are considered redeemable securities under GAAP due to the existence of redemption provisions upon a deemed liquidation event which is outside of our control. Therefore, we present them as temporary equity in the mezzanine section of the Consolidated Balance Sheet. The preferred units have been recorded at their issuance date fair value, net of issuance costs. Because our preferred units are not currently redeemable and we do not have plans or expect any events which constitute a change of control in our partnership agreement, we present our preferred units at their initial carrying amount. However, we would be required to adjust that carrying amount if it becomes probable that we would be required to redeem our preferred units.

Initial and Subsequent Measurement

We initially recognized our preferred units at their issuance date fair value, net of issuance costs. We will not be required to adjust the carrying amount of our preferred units until it becomes probable that they would become redeemable. Once redemption becomes probable, we would adjust the carrying amount of our preferred units to the redemption value over a period of time comprising the date the redemption first becomes probable and the date the units can first be redeemed.

As discussed above, a portion of the net proceeds were allocated to the Preferred Distribution Rate Reset Election and recorded in Other long term liabilities on the Consolidated Balance Sheet as described below (as of the inception date):

| | September 1, 2017 |
|---|---|
| Transaction price, gross | 750,000 |
| Transaction cost to other third parties | (23,581 ) |
| Transaction price, net | 726,419 |

| | |
|---|---|
| Allocation of Net Transaction Price | |
| Preferred Units, net | 691,969 |
| Preferred Distribution Rate Reset Election (Note 19) | 34,450 |
| | 726,419 |

Table of Contents

Preferred unit distributions are recognized on the date in which they are declared. Paid in kind distributions were declared and issued as follows:

| Distribution Declared | Date Issued | Number of Units | Total Amount |
|---|---|---|---|
| 2017 | | | |
| November 2017 | November 14, 2017 | 162,234 | $5,469 |
| 2018 | | | |
| January 2018 | February 14, 2018 | 490,252 | $16,526 |
| April 2018 | May 15, 2018 | 500,976 | $16,888 |
| July 2018 | August 14, 2018 | 511,934 | $17,257 |
| October 2018 | November 14, 2018 | 523,132 | $17,635 |

The following table shows the change in our Class A Convertible Preferred Units from initial measurement at September 1, 2017 to December 31, 2018:

| | Class A Convertible Preferred Units | |
|---|---|---|
| | Units | $ |
| December 31, 2016 | — | $— |
| Issuance of Preferred Units, net | 22,249,494 | 726,419 |
| Allocation to Preferred Distribution Rate Reset Election (Note 19) | — | (34,450 ) |
| Distributions paid-in-kind | 162,234 | 5,469 |
| Allocation of Distributions paid-kind to Preferred Distribution Rate Reset Election (Note 19) | — | (287 ) |
| Balance as of December 31, 2017 | 22,411,728 | $697,151 |
| Distributions paid-in-kind | 2,026,294 | 68,306 |
| Allocation of Distributions paid-kind to Preferred Distribution Rate Reset Election (Note 19) | — | (3,991 ) |
| Balance as of December 31, 2018 | 24,438,022 | $761,466 |

Net income(loss) attributable to common unitholders is reduced by Preferred Unit distributions that accumulated during the period. During 2018, net income attributable to common unitholders was reduced by $69.8 million as a result of distributions that accumulated during the period. With respect to our Class A Convertible Preferred Units relating to the fourth quarter of 2018, we declared a payment-in-kind ("PIK") of the quarterly distribution, which resulted in the issuance of an additional 534,576 Class A Convertible Preferred Units. This PIK amount equates to a distribution of $0.7374 per Class A Convertible Preferred Unit for the 2018 Quarter, or $2.9496 annualized. These distributions were paid on February 14, 2019 to preferred unitholders holders of record at the close of business January 31, 2019.

## 13. Net Income (Loss) Per Common Unit

Basic net income per common unit is computed by dividing net income, after considering income attributable to our Class A preferred unitholders, by the weighted average number of common units outstanding.

The dilutive effect of the Class A Convertible Preferred units is calculated using the if-converted method. Under the if-converted method, the Class A Preferred units are assumed to be converted at the beginning of the period (beginning with their respective issuance date), and the resulting common units are included in the denominator of the diluted net income per common unit calculation for the period being presented. Distributions declared in the period and undeclared distributions that accumulated during the period are added back to the numerator for purposes of the if-converted calculation. For the year ended December 31, 2018, the effect of the assumed conversion of the 24,438,022 Class A convertible preferred units was anti-dilutive and was not included in the computation of diluted earnings per unit.

Table of Contents

The following table reconciles net income (loss) and weighted average units used in computing basic and diluted net income (loss) per common unit (in thousands, except per unit amounts):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Net Income (Loss) Attributable to Genesis Energy L.P. | $(6,075) | $82,647 | $113,249 |
| Less: Accumulated distributions attributable to Class A Convertible Preferred Units | (69,801) | (21,995) | — |
| Net Income (Loss) Available to Common Unitholders | $(75,876) | $60,652 | $113,249 |
| Weighted Average Outstanding Units | 122,579 | 121,546 | 113,433 |
| Basic and Diluted Net Income (Loss) per Common Unit | $(0.62) | $0.50 | $1.00 |

14. Business Segment Information

Our operations consist of four operating segments (see Note 1 for discussion of segment reporting change):

- Offshore Pipeline Transportation – offshore transportation of crude oil and natural gas in the Gulf of Mexico;
- Sodium Minerals and Sulfur Services – trona and trona-based exploring, mining, processing, producing, marketing and selling activities, as well as processing of high sulfur (or “sour”) gas streams for refineries to remove the sulfur, and selling the related by-product, NaHS;
- Onshore Facilities and Transportation – terminaling, blending, storing, marketing, and transporting crude oil, petroleum products (primarily fuel oil, asphalt, and other heavy refined products), and $CO_2$; and
- Marine Transportation – marine transportation to provide waterborne transportation of petroleum products and crude oil throughout North America.

Substantially all of our revenues are derived from, and substantially all of our assets are located in, the United States.

We define Segment Margin as revenues less product costs, operating expenses (excluding non-cash charges, such as depreciation and amortization), and segment general and administrative expenses, plus our equity in distributable cash generated by our equity investees. In addition, our Segment Margin definition excludes the non-cash effects of our legacy stock appreciation rights plan and includes the non-income portion of payments received under direct financing leases.

Our chief operating decision maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including Segment Margin, segment volumes, where relevant, and capital investment.

Table of Contents

Segment information for each year presented below is as follows:

| | Offshore Pipeline Transportation | Sodium Minerals & Sulfur Services | Onshore Facilities & Transportation | Marine Transportation | Total |
|---|---|---|---|---|---|
| Year Ended December 31, 2018 | | | | | |
| Segment Margin [(a)] | $ 285,014 | $260,488 | $ 119,918 | $ 47,338 | $712,758 |
| Capital expenditures [(b)] | $ 4,703 | $74,712 | $ 51,110 | $ 30,868 | $161,393 |
| Revenues: | | | | | |
| External customers | $ 284,544 | $1,181,578 | $ 1,240,382 | $ 206,266 | $2,912,770 |
| Intersegment [(c)] | — | (7,144 ) | (6,527 ) | 13,671 | $— |
| Total revenues of reportable segments | $ 284,544 | $1,174,434 | $ 1,233,855 | $ 219,937 | $2,912,770 |
| Year Ended December 31, 2017 | | | | | |
| Segment Margin [(a)] | $ 317,540 | $130,333 | $ 96,376 | $ 50,294 | $594,543 |
| Capital expenditures [(b)] | $ 8,815 | $1,354,469 | $ 149,123 | $ 68,414 | $1,580,821 |
| Revenues: | | | | | |
| External customers | $ 319,455 | $470,789 | $ 1,044,083 | $ 194,050 | $2,028,377 |
| Intersegment [(c)] | (1,216 ) | (8,167 ) | (1,854 ) | 11,237 | $— |
| Total revenues of reportable segments | $ 318,239 | $462,622 | $ 1,042,229 | $ 205,287 | $2,028,377 |
| Year Ended December 31, 2016 | | | | | |
| Segment Margin [(a)] | $ 336,620 | $79,508 | $ 83,364 | $ 70,079 | $569,571 |
| Capital expenditures [(b)] | $ 46,277 | $2,274 | $ 316,638 | $ 78,804 | $443,993 |
| Revenues: | | | | | |
| External customers | $ 332,514 | $180,665 | $ 993,103 | $ 206,211 | $1,712,493 |
| Intersegment [(c)] | 2,165 | (9,162 ) | 187 | 6,810 | $— |
| Total revenues of reportable segments | $ 334,679 | $171,503 | $ 993,290 | $ 213,021 | $1,712,493 |

Total assets by reportable segment were as follows:

| | December 31, 2018 | December 31, 2017 | December 31, 2016 |
|---|---|---|---|
| Offshore pipeline transportation | 2,359,013 | 2,486,803 | 2,575,335 |
| Sodium minerals and sulfur services | 1,844,845 | 1,848,188 | 395,043 |
| Onshore facilities and transportation | 1,431,910 | 1,927,976 | 1,875,403 |
| Marine transportation | 800,243 | 824,777 | 813,722 |
| Other assets | 43,060 | 49,737 | 43,089 |
| Total consolidated assets | $ 6,479,071 | $ 7,137,481 | $ 5,702,592 |

(a) A reconciliation of total Segment Margin to net income (loss) attributable to Genesis Energy, L.P. for each year is presented below.

(b) Capital expenditures include maintenance and growth capital expenditures, such as fixed asset additions (including enhancements to existing facilities and construction of growth projects) as well as acquisitions of businesses and contributions to equity investees related to same. In addition to construction of growth projects, capital spending in our sodium minerals and sulfur services segment included $1.3 billion during the year ended December 31, 2017 related to the acquisition of our Alkali Business. During the year ended December 31, 2016, capital expenditures in our offshore pipeline transportation segment included $35.1 million related to the acquisition of the remaining 50% ownership in Deepwater Gateway.

(c) Intersegment sales were conducted under terms that we believe were no more or less favorable than then-existing market conditions.

Table of Contents

Reconciliation of total Segment Margin to net income (loss) attributable to Genesis Energy, L.P.:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Total Segment Margin | $712,758 | $594,543 | $569,571 |
| Corporate general and administrative expenses | (64,683) | (60,029) | (40,905) |
| Depreciation, depletion, amortization and accretion | (317,186) | (262,021) | (230,563) |
| Interest expense | (229,191) | (176,762) | (139,947) |
| Adjustment to exclude distributable cash generated by equity investees not included in income and include equity in investees net income [1] | (28,088) | (31,852) | (39,276) |
| Non-cash items not included in Segment Margin | 9,698 | (14,305) | (3,221) |
| Cash payments from direct financing leases in excess of earnings | (7,633) | (6,921) | (6,277) |
| Loss on extinguishment of debt | (3,339) | (6,242) | — |
| Differences in timing of cash receipts for certain contractual arrangements [2] | 6,629 | 17,540 | 13,253 |
| Gain on sales of assets | 42,264 | 40,311 | — |
| Other, net | — | (2,985) | (6,044) |
| Non-cash provision for leased items no longer in use | 476 | (12,589) | — |
| Income tax expense | (1,498) | 3,959 | (3,342) |
| Impairment expense | (126,282) | — | — |
| Net income (loss) attributable to Genesis Energy, L.P. | $(6,075) | $82,647 | $113,249 |

(1) Includes distributions attributable to the period and received during or promptly following such period.

(2) Includes the difference in timing of cash receipts from customers during the period and the revenue we recognize in accordance with GAAP on our related contracts.

15. Transactions with Related Parties

Transactions with related parties were as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Revenues: | | | |
| Sales of $CO_2$ to Sandhill Group, LLC [1] | $1,233 | $2,820 | $3,097 |
| Revenues from services and fees to Poseidon Oil Pipeline Company, LLC [2] | 12,557 | 12,357 | 10,844 |
| Revenues from product sales to ANSAC | 373,606 | 124,536 | — |
| Expenses: | | | |
| Amounts paid to our CEO in connection with the use of his aircraft | $660 | $660 | $660 |
| Charges for products purchased from Poseidon Oil Pipeline Company, LLC [2] | 994 | 986 | 1,007 |
| Charges for services from ANSAC | 5,284 | 2,242 | — |

(1) We owned a 50% interest in Sandhill Group, LLC which was sold in the third quarter of 2018.

(2) We own a 64% interest in Poseidon Oil Pipeline Company, LLC.

Our CEO, Mr. Sims, owns an aircraft which is used by us for business purposes in the course of operations. We pay Mr. Sims a fixed monthly fee and reimburse the aircraft management company for costs related to our usage of the aircraft, including fuel and the actual out-of-pocket costs. Based on current market rates for chartering of private aircraft under long-term, priority arrangements with industry recognized chartering companies, we believe that the terms of this arrangement are no worse than what we could have expected to obtain in an arms-length transaction.

Table of Contents

Transactions with Unconsolidated Affiliates

Poseidon

We provide management, administrative and pipeline operator services to Poseidon under an Operation and Management Agreement . Currently, that agreement renews automatically annually unless terminated by either party (as defined in the agreement). Our revenues for the years ended December 31, 2018, 2017 and 2016 reflect $8.6 million, $8.4 million and $7.9 million, respectively, of fees we earned through the provision of services under that agreement. At December 31, 2018, and 2017, Poseidon Oil Pipeline Company, LLC owed us $2.4 million and $2.2 million, respectively, for services rendered.

ANSAC

We (through a subsidiary of our Alkali Business) are a member of the American Natural Soda Ash Corp. (ANSAC), an organization whose purpose is promoting and increasing the use and sale of natural soda ash and other refined or processed sodium products produced in the U.S. and consumed in specified countries outside of the U.S. Members sell products to ANSAC to satisfy ANSAC’s sales commitments to its customers. ANSAC passes its costs through to its members using a pro rata calculation based on sales. Those costs include sales and marketing, employees, office supplies, professional fees, travel, rent, and certain other costs. Those transactions do not necessarily represent arm's length transactions and may not represent all costs we would otherwise incur if we operated the Alkali Business on a stand-alone basis. We also benefit from favorable shipping rates for our direct exports when using ANSAC to arrange for ocean transport.

Net sales to ANSAC were $373.6 million and $124.5 million for the years ended December 31, 2018 and 2017. The costs charged to us by ANSAC, included in operating costs, were $5.3 million and $2.2 million for the year ended December 31, 2018 and 2017. The 2017 period includes net sales and costs from September 1, 2017 (our acquisition date) to December 31, 2017.

As of December 31, 2018 and 2017, our receivables from and payables to ANSAC were:

| | December 31 2018 | December 31 2017 |
|---|---|---|
| Receivables: | | |
| ANSAC | $ 60,594 | $ 74,490 |
| Payables: | | |
| ANSAC | $ 815 | $ 1,223 |

ANSAC is considered a variable interest entity (VIE) as we do experience certain risks and rewards from our relationship with them. As we do not exercise control over ANSAC and are not considered its primary beneficiary, we do not consolidate ANSAC.

16. Supplemental Cash Flow Information

The following table provides information regarding the net changes in components of operating assets and liabilities:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| (Increase) decrease in: | | | |
| Accounts receivable | $130,573 | $(140,948) | $(9,859) |
| Inventories | 20,963 | 49,055 | (54,361) |
| Deferred charges | (5,826) | (3,622) | (3,902) |
| Other current assets | 9,337 | (410) | 3,059 |
| Increase (decrease) in: | | | |
| Accounts payable | (130,991) | 97,569 | (17,426) |
| Accrued liabilities | (26,208) | 8,512 | (8,161) |
| Net changes in components of operating assets and liabilities | $(2,152) | $10,156 | $(90,650) |

Payments of interest and commitment fees were $228.3 million, $168.3 million and $157.4 million during the years ended December 31, 2018, 2017 and 2016, respectively. We capitalized interest of $3.4 million, $15.0 million and

$26.6 million during the years ended December 31, 2018, 2017 and 2016.

Table of Contents

During the years ended December 31, 2018, 2017 and 2016, we paid taxes of $0.2 million, $1.0 million and $1.3 million.
At December 31, 2018, 2017 and 2016, we had incurred liabilities for fixed and intangible asset additions totaling $9.4 million, $39.7 million and $33.7 million, respectively, which had not been paid at the end of the year. Therefore, these amounts were not included in the caption "Payments to acquire fixed and intangible assets" under Cash Flows from Investing Activities in the Consolidated Statements of Cash Flows.

17. Equity-Based Compensation Plans
2010 Long Term Incentive Plan
In 2010, we adopted the 2010 Long-Term Incentive Plan (the "2010 Plan"). The 2010 Plan provides for the awards of phantom units and distribution equivalent rights to members of our board of directors and employees who provide services to us. Phantom units are notional units representing unfunded and unsecured promises to pay to the participant a specified amount of cash based on the market value of our common units should specified vesting requirements be met. Distribution equivalent rights ("DERs") are tandem rights to receive on a quarterly basis a cash amount per phantom unit equal to the amount of cash distributions paid per common unit. The 2010 Plan is administered by the Governance, Compensation and Business Development Committee (the "G&C Committee") of our board of directors. The G&C Committee (at its discretion) designates participants in the 2010 Plan, determines the types of awards to grant to participants, determines the number of units to be covered by any award, and determines the conditions and terms of any award including vesting, settlement and forfeiture conditions.
The compensation cost associated with the phantom units is re-measured each reporting period based on the market value of our common units, and is recognized over the vesting period. The liability recorded for the estimated amount to be paid to the participants under the 2010 Plan is adjusted to recognize changes in the estimated compensation cost and vesting. Management's estimates of the fair value of these awards granted in 2018 are adjusted for assumptions about expected forfeitures of units prior to vesting. For our performance-based awards, our fair value estimates are weighted based on probabilities for each performance condition applicable to the award.
During 2018, we granted 28,484 phantom units with tandem DERs at a weighted average grant fair value of $22.12 per unit. During 2017, we granted 297,214 phantom units with tandem DERs at a weighted average grant date fair value of $32.37 per unit. During 2016, we granted 339,584 phantom units with tandem DERs at a weighted average grant date fair value of $30.71 per unit. The phantom units granted during 2018 were made only to directors. Awards to management and other key employees during 2018 were made under the 2018 LTIP plan, and were non-equity awards. The phantom units granted during 2017 and 2016 were both service-based and performance-based awards. The service-based awards vest on the third anniversary of the date of grant. Performance-based phantom unit awards granted in 2016 and 2017 will vest on the third anniversary of issuance, in an amount ranging from 0% to 150% of the targeted number of phantom units, if certain quarterly cash distribution per common unit targets are achieved in the fourth quarter of 2019 and 2020, respectively. If the quarterly cash distribution per common unit is below the threshold target, all of the performance-based phantom units granted will be forfeited.

A summary of our phantom unit activity for our service-based and performance-based awards is set forth below:

| | Service-Based Awards | | | Performance-Based Awards | | |
|---|---|---|---|---|---|---|
| | Number of Phantom Units | Average Grant Date Fair Value | Total Value (in thousands) | Number of Phantom Units | Average Grant Date Fair Value | Total Value (in thousands) |
| Unvested at December 31, 2017 | 239,837 | $ 34.81 | $ 8,349 | 582,375 | $ 34.73 | $ 20,228 |
| Granted | 28,484 | $ 22.12 | 630 | — | $ — | — |
| Forfeited | (17,073 ) | $ 31.46 | (537 ) | (67,266 ) | $ 33.49 | (2,253 ) |
| Settled | (55,309 ) | $ 44.92 | (2,484 ) | (137,103) | $ 45.40 | (6,224 ) |
| Unvested at December 31, 2018 | 195,939 | $ 30.40 | $ 5,958 | 378,006 | $ 31.09 | $ 11,751 |

At December 31, 2018, we estimated the unrecognized compensation cost of our phantom awards to be approximately $0.6 million to be recognized over a weighted average period of approximately 0.8 years. We recorded a charge of $2.1 million and a credit of $3.4 million to compensation expense for the years ended December 31, 2018 and 2017, respectively. Our liability for these awards totaled $3.3 million and $3.2 million at December 31, 2018 and 2017, respectively.

Table of Contents

Equity-Based Compensation Plan Expense

Equity-based compensation expense during the three years ended December 31, 2018 was as follows:

| | Expense Related to Equity-Based Compensation Plans | | |
|---|---|---|---|
| Consolidated Statement of Operations | 2018 | 2017 | 2016 |
| Onshore facilities and transportation operating costs | $140 | $(1,137) | $1,688 |
| Marine transportation operating costs | 183 | (483) | 1,089 |
| Sodium minerals and sulfur services operating costs | 112 | (533) | 547 |
| Offshore pipeline operating costs | 297 | (152) | 681 |
| General and administrative expenses | 1,239 | (2,272) | 4,575 |
| Total | $1,971 | $(4,577) | $8,580 |

18. Major Customers and Credit Risk

Due to the nature of our onshore facilities and transportation operations, a disproportionate percentage of our trade receivables constitute obligations of refiners, large crude oil producers and integrated oil companies. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers could be affected by similar changes in economic, industry or other conditions. However, we believe that the credit risk posed by this industry concentration is offset by the creditworthiness of our customer base. Our portfolio of accounts receivable is comprised in large part of accounts owed by integrated and large independent energy companies with stable payment histories. The credit risk related to contracts which are traded on the NYMEX is limited due to daily margin requirements and other NYMEX requirements.

We have established various procedures to manage our credit exposure, including initial credit approvals, credit limits, collateral requirements and rights of offset. Letters of credit, prepayments and guarantees are also utilized to limit credit risk to ensure that our established credit criteria are met.

During 2018, 2017 and 2016 our largest customer was Shell Oil Company, which accounted for 11%, 13%, and 12% of total revenues, respectively. The revenues from Shell Oil Company in all three years relate primarily to our onshore facilities and transportation operations.

In addition, as discussed in Note 15, we are a member of ANSAC, an organization whose purpose is promoting and increasing the use and sale of natural soda ash and other refined or processed sodium products produced in the U.S. and consumed in specified countries outside of the U.S. Members sell products to ANSAC to satisfy ANSAC's sales commitments to its customers. Given this relationship, a large portion of our soda ash production is sold to ANSAC. As such, a disproportionate amount of our trade receivables and sales in our sodium minerals and sulfur services segment are related to ANSAC.

19. Derivatives

Commodity Derivatives

We have exposure to commodity price changes related to our inventory and purchase commitments. We utilize derivative instruments (primarily futures and options contracts traded on the NYMEX) to hedge our exposure to commodity prices, primarily of crude oil, fuel oil and petroleum products. Our decision as to whether to designate derivative instruments as fair value hedges for accounting purposes relates to our expectations of the length of time we expect to have the commodity price exposure and our expectations as to whether the derivative contract will qualify as highly effective under accounting guidance in limiting our exposure to commodity price risk. Most of the petroleum products, including fuel oil that we supply cannot be hedged with a high degree of effectiveness with derivative contracts available on the NYMEX; therefore, we do not designate derivative contracts utilized to limit our price risk related to these products as hedges for accounting purposes. Typically we utilize crude oil and other petroleum products futures and option contracts to limit our exposure to the effect of fluctuations in petroleum products prices on the future sale of our inventory or commitments to purchase petroleum products, and we recognize any changes in fair value of the derivative contracts as increases or decreases in our cost of sales. The recognition of changes in fair value of the derivative contracts not designated as hedges for accounting purposes can

Table of Contents

occur in reporting periods that do not coincide with the recognition of gain or loss on the actual transaction being hedged. Therefore we will, on occasion, report gains or losses in one period that will be partially offset by gains or losses in a future period when the hedged transaction is completed.

We have designated certain crude oil futures contracts as hedges of crude oil inventory due to our expectation that these contracts will be highly effective in hedging our exposure to fluctuations in crude oil prices during the period that we expect to hold that inventory. We account for these derivative instruments as fair value hedges under the accounting guidance. Changes in the fair value of these derivative instruments designated as fair value hedges are used to offset related changes in the fair value of the hedged crude oil inventory. Any hedge ineffectiveness in these fair value hedges and any amounts excluded from effectiveness testing are recorded as a gain or loss in the Consolidated Statement of Operations.

In accordance with NYMEX requirements, we fund the margin associated with our loss positions on commodity derivative contracts traded on the NYMEX. The amount of the margin is adjusted daily based on the fair value of the commodity contracts. The margin requirements are intended to mitigate a party’s exposure to market volatility and the associated contracting party risk. We offset fair value amounts recorded for our NYMEX derivative contracts against margin funding as required by the NYMEX in Current Assets - Other in our Consolidated Balance Sheets.

Additionally, in 2018 we entered into swap arrangements. Our Alkali Business relies on natural gas to generate heat and electricity for operations. We use a combination of commodity price swap contracts and future purchase contracts to manage our exposure to fluctuations in natural gas prices. The swap contracts fix the basis differential between NYMEX Henry Hub and NW Rocky Mountain posted prices. We do not designate these contracts as hedges for accounting purposes. We recognize any changes in fair value of the derivative contracts as increases or decreases in our cost of sales.

At December 31, 2018, we had the following outstanding derivative commodity contracts that were entered into to economically hedge inventory or fixed price purchase commitments.

| | Sell (Short) Contracts | Buy (Long) Contracts |
|---|---|---|
| Designated as hedges under accounting rules: | | |
| Crude oil futures: | | |
| Contract volumes (1,000 bbls) | 56 | — |
| Weighted average contract price per bbl | $ 53.11 | — |
| Not qualifying or not designated as hedges under accounting rules: | | |
| Crude oil futures: | | |
| Contract volumes (1,000 bbls) | 293 | 234 |
| Weighted average contract price per bbl | $ 49.85 | $ 49.37 |
| Natural gas swaps: | | |
| Contract volumes (10,000 MMBTU) | 502 | — |
| Weighted average price differential per MMBTU | $ 0.62 | — |
| Natural gas futures: | | |
| Contract volumes (10,000 MMBTU) | 137 | 590 |
| Weighted average contract price per MMBTU | $ 3.53 | $ 2.91 |
| Diesel futures: | | |
| Contract volumes (1,000 bbls) | 2 | 2 |
| Weighted average contract price per bbl | $ 1.89 | $ 1.85 |
| NYM RBOB Gas futures: | | |
| Contract volumes (42,000 gallons) | 2 | 1 |
| Weighted average contract price per gallon | $ 1.35 | $ 1.29 |
| Fuel oil futures: | | |
| Contract volumes (1,000 bbls) | 382 | 40 |
| Weighted average contract price per bbl | $ 51.41 | $ 49.94 |
| Crude oil options: | | |

| | | |
|---|---|---|
| Contract volumes (1,000 bbls) | 26 | — |
| Weighted average premium received | $ 2.66 | $ — |

Table of Contents

Financial Statement Impacts

The following table summarizes the accounting treatment and classification of our derivative instruments on our Consolidated Financial Statements.

| | | Impact of Unrealized Gains and Losses | |
|---|---|---|---|
| Derivative Instrument | Hedged Risk | Consolidated Balance Sheets | Consolidated Statements of Operations |
| Designated as hedges under accounting guidance: | | | |
| Crude oil futures contracts (fair value hedge) | Volatility in crude oil prices - effect on market value of inventory | Derivative is recorded in Other current assets (offset against margin deposits) and offsetting change in fair value of inventory is recorded in Inventories | Excess, if any, over effective portion of hedge is recorded in Onshore facilities and transportation costs - product costs<br>Effective portion is offset in cost of sales against change in value of inventory being hedged |
| Not qualifying or not designated as hedges under accounting guidance: | | | |
| Commodity hedges consisting of crude oil, heating oil and natural gas futures, forward contracts, swaps and call options | Volatility in crude oil, natural gas and petroleum products prices - effect on market value of inventory or purchase commitments | Derivative is recorded in Other current assets (offset against margin deposits) or Accrued liabilities | Entire amount of change in fair value of derivative is recorded in Onshore facilities and transportation costs - product costs and Sodium minerals and sulfur services - operating costs |
| Preferred Distribution Rate Reset Election | This instrument is not related to a risk, but is rather part of a host contract with the issuance of our Preferred Units | Derivative is recorded in Other long-term liabilities | Entire amount of change in fair value of derivative is recorded in Other income (expense) |

Unrealized gains are subtracted from net income and unrealized losses are added to net income in determining cash flows from operating activities. To the extent that we have fair value hedges outstanding, the offsetting change recorded in the fair value of inventory is also eliminated from net income in determining cash flows from operating activities. Changes in margin deposits necessary to fund unrealized losses also affect cash flows from operating activities.

Table of Contents

The following tables reflect the estimated fair value gain (loss) position of our derivatives at December 31, 2018 and 2017:

Fair Value of Derivative Assets and Liabilities

| | Consolidated Balance Sheets Location | Fair Value December 31, 2018 | December 31, 2017 |
|---|---|---|---|
| Asset Derivatives: | | | |
| Commodity derivatives—futures and call options (undesignated hedges): | | | |
| Gross amount of recognized assets | Current Assets - Other | $3,431 | $ 505 |
| Gross amount offset in the Consolidated Balance Sheets | Current Assets - Other | (1,361) | (505) |
| Net amount of assets presented in the Consolidated Balance Sheets | | $2,070 | $ — |
| Natural Gas Swap (undesignated hedge) | Current Assets - Other | 1,274 | — |
| Commodity derivatives—futures and call options (designated hedges): | | | |
| Gross amount of recognized assets | Current Assets - Other | $469 | $ 54 |
| Gross amount offset in the Consolidated Balance Sheets | Current Assets - Other | (44) | (54) |
| Net amount of assets presented in the Consolidated Balance Sheets | | $425 | $ — |
| Liability Derivatives: | | | |
| Preferred Distribution Rate Reset Election (2) | Other Long-Term Liabilities (2) | $(40,840) | $ (45,209) |
| Natural Gas Swap (undesignated hedge) | Current Liabilities - Accrued Liabilities | (125) | — |
| Commodity derivatives—futures and call options (undesignated hedges): | | | |
| Gross amount of recognized liabilities | Current Assets - Other (1) | $(1,361) | $ (1,203) |
| Gross amount offset in the Consolidated Balance Sheets | Current Assets - Other (1) | 1,361 | 1,203 |
| Net amount of liabilities presented in the Consolidated Balance Sheets | | $— | $ — |
| Commodity derivatives—futures and call options (designated hedges): | | | |
| Gross amount of recognized liabilities | Current Assets - Other (1) | $(44) | $ (863) |
| Gross amount offset in the Consolidated Balance Sheets | Current Assets - Other (1) | 44 | 338 |
| Net amount of liabilities presented in the Consolidated Balance Sheets | | $— | $ (525) |

(1) These derivative liabilities have been funded with margin deposits recorded in our Consolidated Balance Sheets under Current Assets - Other.

(2) Refer to Note 12 and Note 20 for additional discussion surrounding the Preferred Distribution Rate Reset Election derivative.

Our accounting policy is to offset derivative assets and liabilities executed with the same counterparty when a master netting arrangement exists. Accordingly, we also offset derivative assets and liabilities with amounts associated with cash margin. Our exchange-traded derivatives are transacted through brokerage accounts and are subject to margin requirements as established by the respective exchange. On a daily basis, our account equity (consisting of the sum of our cash balance and the fair value of our open derivatives) is compared to our initial margin requirement resulting in the payment or return of variation margin. As of December 31, 2018, we had a net broker receivable of approximately $2.2 million (consisting of initial margin

Table of Contents

of $3.1 million decreased by $0.9 million of variation margin). As of December 31, 2017, we had a net broker receivable of approximately $1.0 million (consisting of initial margin of $1.3 million decreased by $0.3 million of variation margin). At December 31, 2018 and December 31, 2017, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact to us upon any change in our credit ratings.

Preferred Distribution Rate Reset Election

A derivative feature embedded in a contract that does not meet the definition of a derivative in its entirety must be bifurcated and accounted for separately if the economic characteristics and risks of the embedded derivative are not clearly and closely related to those of the host contract. For a period of 30 days following (i) September 1, 2022 and (ii) each subsequent anniversary thereof, the holders of our preferred units may make a Rate Reset Election to a cash amount per preferred unit equal to the amount that would be payable per quarter if a preferred unit accrued interest on the Issue Price at an annualized rate equal to three-month LIBOR plus 750 basis points; provided, however, that such reset rate shall be equal to 10.75% if (i) such alternative rate is higher than the LIBOR-based rate and (ii) the then market price for our common units is then less than 110% of the Issue Price. The Rate Reset Election of the preferred units represents an embedded derivative that must be bifurcated from the related host contract and recorded at fair value on our Consolidated Balance Sheet. Corresponding changes in fair value are recognized in Other Income (Expense) in our Consolidated Statement of Operations. At December 31, 2018, the fair value of this embedded derivative was a liability of $40.8 million. See Note 12 for additional information regarding our Class A convertible preferred units and the Rate Reset Election.

Effect on Operating Results

| | | Amount of Gain (Loss) Recognized in Income Year Ended December 31, | | |
|---|---|---|---|---|
| | Consolidated Statements of Operations Location | 2018 | 2017 | 2016 |
| Commodity derivatives—futures and call options: | | | | |
| Contracts designated as hedges under accounting guidance | Onshore facilities and transportation product costs | $(544) | $5,116 | $(13,195) |
| Contracts not considered hedges under accounting guidance | Onshore facilities and transportation product costs, sodium minerals and sulfur services operating costs | 3,914 | (1,314) | (5,847) |
| Total commodity derivatives | | $3,370 | $3,802 | $(19,042) |
| Natural Gas Swap | Sodium minerals and sulfur services operating costs | 1,906 | $— | $— |
| Preferred Distribution Rate Reset Election (Note 20) | Other Income (Expense) | $8,360 | $(10,472) | $— |

We have no derivative contracts with credit contingent features.

20. Fair-Value Measurements

We classify financial assets and liabilities into the following three levels based on the inputs used to measure fair value:

(1) Level 1 fair values are based on observable inputs such as quoted prices in active markets for identical assets and liabilities;

(2) Level 2 fair values are based on pricing inputs other than quoted prices in active markets for identical assets and liabilities and are either directly or indirectly observable as of the measurement date; and

(3) Level 3 fair values are based on unobservable inputs in which little or no market data exists.

As required by fair value accounting guidance, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

Table of Contents

Our assessment of the significance of a particular input to the fair value requires judgment and may affect the placement of assets and liabilities within the fair value hierarchy levels.
The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2018 and 2017.

| | December 31, 2018 | | | December 31, 2017 | | |
|---|---|---|---|---|---|---|
| Recurring Fair Value Measures | Level 1 | Level 2 | Level 3 | Level 1 | Level 2 | Level 3 |
| Commodity derivatives: | | | | | | |
| Assets | $3,900 | $1,274 | $— | $559 | $ — | $— |
| Liabilities | $(1,405) | $(125) | $— | $(2,066) | $ — | $— |
| Preferred Distribution Rate Reset Election | $— | $— | $(40,840) | $— | $ — | $(45,209) |

Rollforward of Level 3 Fair Value Measurements

The following table provides a reconciliation of changes in fair value at the beginning and ending balances for our derivatives classified as level 3:

| | |
|---|---|
| Balance as of December 31, 2016 | — |
| Initial valuation of Preferred Distribution Rate Reset Election | (34,450) |
| Net Loss for the period including earnings | (10,472) |
| Allocation of Distribution Paid-in-kind | (287) |
| Balance as of December 31, 2017 | (45,209) |
| Net gain for the period included in earnings | 8,360 |
| Allocation of Distribution Paid-in-kind | (3,991) |
| Balance as of December 31, 2018 | $(40,840) |

Our commodity derivatives include exchange-traded futures and exchange-traded options contracts. The fair value of these exchange-traded derivative contracts is based on unadjusted quoted prices in active markets and is, therefore, included in Level 1 of the fair value hierarchy. The fair value of the swaps contracts was determined using market price quotations and a pricing model. The swap contracts were considered a level 2 input in the fair value hierarchy at December 31, 2018.
The fair value of embedded derivative feature is based on a valuation model that estimates the fair value of the convertible preferred units with and without a Rate Reset Election. This model contains inputs, including our common unit price, a ten year history of the dividend yield, default probabilities and timing estimates which involve management judgment. A significant increase or decrease in the value of these inputs could result in a material change in fair value to this embedded derivative feature. We report unrealized gains and losses associated with this embedded derivative in our Consolidated Statements of Operations as Other income (expense), net.
See Note 19 for additional information on our derivative instruments.
Nonfinancial Assets and Liabilities
We utilize fair value on a non-recurring basis to perform impairment tests as required on our property, plant and equipment, goodwill and intangible assets. Assets and liabilities acquired in business combinations are recorded at their fair value as of the date of acquisition. The inputs used to determine such fair value are primarily based upon internally developed cash flow models and would generally be classified in Level 3, in the event that we were required to measure and record such assets within our Consolidated Financial Statements. Additionally, we use fair value to determine the inception value of our asset retirement obligations. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition, and would generally be classified in Level 3.

Other Fair Value Measurements

We believe the debt outstanding under our credit facility approximates fair value as the stated rate of interest approximates current market rates of interest for similar instruments with comparable maturities. At December 31, 2018 our

Table of Contents

senior unsecured notes had a carrying value of $2.5 billion and a fair value of $2.3 billion, compared to $2.6 billion and $2.7 billion, respectively at December 31, 2017. The fair value of the senior unsecured notes is determined based on trade information in the financial markets of our public debt and is considered a Level 2 fair value measurement.

21. Employee Benefit Plans

Upon acquisition of our Alkali Business in 2017, we now sponsor a defined benefit plan. We account for the Alkali Business benefit plan as a single employer pension plan that benefits only employees of our Alkali Business, and thus, the related assets and liability costs of the plan are recorded in the Consolidated Balance Sheet. Under the Alkali Business benefit plan, each eligible employee will automatically become a participant upon completion of one year of credited service. Retirement benefits under this plan are calculated based on the total years of service of an eligible participant, multiplied by a specified benefit rate in effect at the termination of the plan participant's years of service. The change in benefit obligations, plan assets and funded status along with amounts recognized in the Consolidated Balance Sheet are as follows:

| | December 31, | |
|---|---|---|
| | 2018 | 2017 |
| Change in benefit obligation: | | |
| Benefit Obligation, beginning of year | $22,530 | $— |
| Service Cost | 5,153 | 1,749 |
| Interest Cost | 862 | 267 |
| Actuarial (Gain) Loss | (3,816) | 992 |
| Benefits Paid | (218) | (56) |
| Acquisition of Alkali Business | — | 19,578 |
| Benefit Obligation, end of year | 24,511 | 22,530 |
| | | |
| Change in plan assets: | | |
| Fair Value of Plan Assets, beginning of year | 13,306 | — |
| Actual Return (loss) on Plan Assets | (1,300) | 647 |
| Employer Contributions | 3,928 | 2,250 |
| Benefits Paid | (218) | (56) |
| Acquisition of Alkali Business | — | 10,465 |
| Fair Value of Plan assets, end of year | 15,716 | 13,306 |
| Funded Status at end of period | $(8,795) | $(9,224) |
| Amounts recognized in the Consolidated Balance Sheet: | | |
| Non-current assets | $— | $— |
| Current liabilities | — | — |
| Non-current Liabilities | (8,795) | (9,224) |
| Net Liability at end of year | $(8,795) | $(9,224) |
| | | |
| Amounts recognized in accumulated other comprehensive income (loss): | | |
| Net actuarial (gain) loss | (939) | 604 |
| Amounts recognized in accumulated other comprehensive income ( loss:) | $(939) | $604 |

Table of Contents

Estimated Future Cash Flows- The following employer contributions and benefit payments, which reflect expected future service, are expected to be paid as follows:

| | |
|---|---|
| Employer Contributions | |
| Expected 2019 Contributions by Employer | $3,550 |
| Future Expected Benefit Payments | |
| 2019 | $587 |
| 2020 | 816 |
| 2021 | 962 |
| 2022 | 1,109 |
| 2023 | 1,265 |
| 2024-2028 | 8,465 |

Net Periodic Pension Costs- The components of net periodic pension costs for the Alkali benefit plan are as follows:

| | December 31, | |
|---|---|---|
| | 2018 | 2017 |
| Service Cost | $5,153 | $1,749 |
| Interest Cost | 862 | 267 |
| Expected Return on Assets | (973) | (259) |
| | $5,042 | $1,757 |

Significant Assumptions- Discount rates are determined annually and are based on rates of return of high-quality long-term fixed income securities currently available and expected to be available during the maturity of the pension benefits.

The long-term rate of return estimation for the Alkali benefit plan is based on a capital asset pricing model using historical data and a forecasted earnings model. An expected return on plan assets analysis is performed which incorporates the current portfolio allocation, historical asset-class returns and an assessment of expected future performance using asset-class risk factors.

The Alkali Business benefit plan is administered by a Board-appointed committee that has fiduciary responsibility for the plan's management. The committee is responsible for the oversight and management of the plan's investments. The committee maintains an investment policy that provides guidelines for selection and retention of investment managers or funds, allocation of plan assets and performance review procedures and updating of the policy. The objective of the committee's investment policy is to manage the plan assets in such a way that will allow for the on-going payment of the Company's obligation to the beneficiaries.

| Weighted average assumptions used to determine benefit obligation: | December 31, 2018 | December 31, 2017 |
|---|---|---|
| Discount Rate | 4.62 % | 3.90 % |
| Expected Long-term Rate of Return | 6.41 % | 6.28 % |
| Rate of Compensation Increase | N/A | N/A |

The discount rate used to determine the net periodic cost at the beginning of the period was 3.90%.

Table of Contents

Pension Plan Assets - We maintain target allocation percentages among various asset classes based on an investment policy established for our Pension Plan. The target allocation is designed to achieve long term objectives of return, mitigating risk, and considering expected cash flows. Our Pension Plan asset allocations at December 31, 2018 by asset category are as follows:

December 31, 2018

| | Target % | Actual % |
|---|---|---|
| Equity securities | 41-60% | 51 % |
| Fixed income securities | 40-50% | 41 % |
| Other | 0-10% | 8 % |

A summary of total investments for our pension plan assets measured at fair value is presented as of December 31 for the periods below:

| | 2018 | | | | 2017 | | | |
|---|---|---|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total | Level 1 | Level 2 | Level 3 | Total |
| Cash and cash equivalents | 506 | — | — | $506 | 260 | — | — | $260 |
| Equity securities | 8,038 | — | — | $8,038 | 2,518 | — | — | $2,518 |
| Mutual and other exchange traded funds | 7,172 | — | — | $7,172 | 10,528 | — | — | $10,528 |
| | 15,716 | — | — | $15,716 | 13,306 | — | — | $13,306 |

22. Commitments and Contingencies

Commitments and Guarantees

Our office lease for our corporate headquarters extends until October 31, 2022. To transport products, we lease tractors, trailers and railcars. In addition, we lease tanks and terminals for the storage of crude oil, petroleum products, NaHS and caustic soda. Additionally, we lease a segment of pipeline where under the terms we make payments based on throughput. We have no minimum volumetric or financial requirements remaining on our pipeline lease.

The future minimum rental payments under all non-cancelable operating leases as of December 31, 2018, were as follows (in thousands):

| | Office Space | Transportation Equipment | Terminals and Tanks | Total |
|---|---|---|---|---|
| 2019 | $4,197 | $ 27,547 | $ 14,298 | $46,042 |
| 2020 | 4,119 | 24,642 | 10,594 | 39,355 |
| 2021 | 3,298 | 19,536 | 7,840 | 30,674 |
| 2022 | 2,692 | 18,113 | 6,653 | 27,458 |
| 2023 | 961 | 17,290 | 9,378 | 27,629 |
| 2024 and thereafter | 3,735 | 45,390 | 77,104 | 126,229 |
| Total minimum lease obligations | $19,002 | $ 152,518 | $ 125,867 | $297,387 |

Total operating lease expense from our continuing operations was as follows (in thousands):

| | |
|---|---|
| Year Ended December 31, 2018 | $30,798 |
| Year Ended December 31, 2017 | $36,933 |
| Year Ended December 31, 2016 | $41,906 |

Table of Contents

We are subject to various environmental laws and regulations. Policies and procedures are in place to monitor compliance and to detect and address any releases of crude oil from our pipelines or other facilities; however no assurance can be made that such environmental releases may not substantially affect our business.

Other Matters

Our facilities and operations may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury or loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance that we consider adequate to cover our operations and properties, in amounts we consider reasonable. Our insurance does not cover every potential risk associated with operating our facilities, including the potential loss of significant revenues. The occurrence of a significant event that is not fully-insured could materially and adversely affect our results of operations. We believe we are adequately insured for public liability and property damage to others and that our coverage is similar to other companies with operations similar to ours. No assurance can be made that we will be able to maintain adequate insurance in the future at premium rates that we consider reasonable.

We are subject to lawsuits in the normal course of business and examination by tax and other regulatory authorities. We do not expect such matters presently pending to have a material effect on our financial position, results of operations or cash flows.

23. Income Taxes

We are not a taxable entity for federal income tax purposes. As such, we do not directly pay federal income taxes. Other than with respect to our corporate subsidiaries and the Texas Margin Tax, our taxable income or loss is includible in the federal income tax returns of each of our partners.

A few of our operations are owned by wholly-owned corporate subsidiaries that are taxable as corporations. We pay federal and state income taxes on these operations.

As a result of the Tax Cuts and Jobs Act enacted on December 22, 2017, The Partnership remeasured its U.S. deferred tax assets and liabilities during the year ended December 31, 2017 and recorded a $5.3 million benefit relating to the U.S. federal corporate tax rate change.

Our income tax (benefit) expense is as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Current: | | | |
| Federal | $— | $— | $— |
| State | 810 | 100 | 1,200 |
| Total current income tax expense | $810 | $100 | $1,200 |
| Deferred: | | | |
| Federal | $114 | $(5,530) | $1,862 |
| State | 574 | 1,471 | 280 |
| Total deferred income tax expense (benefit) | $688 | $(4,059) | $2,142 |
| Total income tax expense (benefit) | $1,498 | $(3,959) | $3,342 |

Table of Contents

Deferred income taxes relate to temporary differences based on tax laws and statutory rates that were enacted at the balance sheet date. Deferred tax assets and liabilities consist of the following:

| | December 31, | |
|---|---|---|
| | 2018 | 2017 |
| Deferred tax assets: | | |
| Net operating loss carryforwards | $11,491 | $9,506 |
| Total long-term deferred tax asset | 11,491 | 9,506 |
| Valuation allowances | (1,758) | (1,285) |
| Total deferred tax assets | $9,733 | $8,221 |
| Deferred tax liabilities: | | |
| Long-term: | | |
| Fixed assets | $(2,893) | $(3,896) |
| Intangible assets | (18,209) | (15,797) |
| Other | (1,207) | (441) |
| Total long-term liability | (22,309) | (20,134) |
| Total deferred tax liabilities | $(22,309) | $(20,134) |
| Total net deferred tax liability | $(12,576) | $(11,913) |

We record a valuation allowance when it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of the deferred tax assets depends on the ability to generate sufficient taxable income of the appropriate character in the future and in the appropriate taxing jurisdictions.

The reconciliation between the Partnership's effective tax rate on income (loss) from operations and the statutory tax rate is as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Income(loss) from operations before income taxes | $(10,294) | $78,120 | $114,424 |
| Partnership income not subject to federal income tax | 10,824 | (77,704) | (109,111) |
| Income subject to federal income taxes | $530 | $416 | $5,313 |
| Tax expense at federal statutory rate | $111 | $146 | $1,860 |
| State income taxes, net of federal tax | 1,285 | 1,396 | 949 |
| Return to provision, federal and state | (128) | (163) | (198) |
| Other | 230 | (68) | 731 |
| Re-measurement of deferred taxes due to enacted tax rate change | — | (5,270) | — |
| Income tax expense (benefit) | $1,498 | $(3,959) | $3,342 |
| Effective tax rate on income from operations before income taxes | (15)% | (5)% | 3% |

At December 31, 2018, 2017 and 2016, we had no uncertain tax positions.

Table of Contents

24. Quarterly Financial Data (Unaudited)

The table below summarizes our unaudited quarterly financial data for 2018 and 2017.

| | 2018 Quarters | | | |
|---|---|---|---|---|
| | First | Second | Third | Fourth |
| Revenues from continuing operations | $725,808 | $752,388 | $745,278 | $689,296 |
| Operating income | $59,081 | $60,900 | $46,148 | $4,119 |
| Net income (loss) | $7,898 | $10,871 | $(1,634 ) | $(28,927 ) |
| Net loss attributable to noncontrolling interest | $136 | $126 | $1,311 | $4,144 |
| Net income (loss) attributable to Genesis Energy, L.P. | $8,034 | $10,997 | $(323 ) | $(24,783 ) |
| Basic and diluted net income (loss) per common unit: | | | | |
| Net income (loss) per common unit | $(0.07 ) | $(0.05 ) | $(0.15 ) | $(0.35 ) |
| Cash distributions per common unit [1] | $0.5200 | $0.5300 | $0.5400 | $0.5500 |

| | 2017 Quarters | | | |
|---|---|---|---|---|
| | First | Second | Third | Fourth |
| Revenues from continuing operations | $415,491 | $406,723 | $486,114 | $720,049 |
| Operating income | $52,597 | $61,447 | $43,100 | $63,407 |
| Net income | $26,938 | $33,580 | $6,160 | $15,401 |
| Net loss attributable to noncontrolling interest | $152 | $153 | $152 | $111 |
| Net income attributable to Genesis Energy, L.P. | $27,090 | $33,733 | $6,312 | $15,512 |
| Basic and diluted net income (loss) per common unit: | | | | |
| Net income (loss) per common unit | $0.23 | $0.28 | $0.01 | $(0.01 ) |
| Cash distributions per common unit [1] | $0.7100 | $0.7200 | $0.7225 | $0.5000 |

(1) Represents cash distributions declared and paid in the applicable period.

25. Condensed Consolidating Financial Information

Our $2.5 billion aggregate principal amount of senior unsecured notes co-issued by Genesis Energy, L.P. and Genesis Energy Finance Corporation are fully and unconditionally guaranteed jointly and severally by all of Genesis Energy, L.P.'s current and future 100% owned domestic subsidiaries, except Genesis Free State Pipeline, LLC, Genesis NEJD Pipeline, LLC and certain other minor subsidiaries. Genesis NEJD Pipeline, LLC is 100% owned by Genesis Energy, L.P., the parent company. The remaining non-guarantor subsidiaries are owned by Genesis Crude Oil, L.P., a guarantor subsidiary. Genesis Energy Finance Corporation has no independent assets or operations. See Note 11 for additional information regarding our consolidated debt obligations.

Table of Contents

The following is condensed consolidating financial information for Genesis Energy, L.P. and subsidiary guarantors:

Condensed Consolidating Balance Sheet
December 31, 2018

| | Genesis Energy, L.P. (Parent and Co-Issuer) | Genesis Energy Finance Corporation (Co-Issuer) | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Eliminations | Genesis Energy, L.P. Consolidated |
|---|---|---|---|---|---|---|
| ASSETS | | | | | | |
| Current assets: | | | | | | |
| Cash and cash equivalents | $6 | $ — | $8,968 | $ 1,326 | $— | $10,300 |
| Other current assets | 50 | — | 419,809 | 13,285 | (165) | 432,979 |
| Total current assets | 56 | — | 428,777 | 14,611 | (165) | 443,279 |
| Fixed Assets, at cost | — | — | 5,363,274 | 77,584 | — | 5,440,858 |
| Less: Accumulated depreciation | — | — | (994,609) | (29,216) | — | (1,023,825) |
| Net fixed assets | — | — | 4,368,665 | 48,368 | — | 4,417,033 |
| Mineral Leaseholds, net of accumulated depletion | — | — | 560,481 | — | — | 560,481 |
| Goodwill | — | — | 301,959 | — | — | 301,959 |
| Other assets, net of amortization | 10,776 | — | 440,312 | 117,766 | (167,620) | 401,234 |
| Advances to affiliates | 3,305,568 | — | — | 103,061 | (3,408,629) | — |
| Equity investees | — | — | 355,085 | — | — | 355,085 |
| Investments in subsidiaries | 2,648,510 | — | 60,532 | — | (2,709,042) | — |
| Total assets | $5,964,910 | $ — | $6,515,811 | $ 283,806 | $(6,285,456) | $6,479,071 |
| LIABILITIES AND CAPITAL | | | | | | |
| Current liabilities | $39,342 | $ — | $266,252 | $ 27,350 | $(110) | $332,834 |
| Senior secured credit facility | 970,100 | — | — | — | — | 970,100 |
| Senior unsecured notes, net of debt issuance costs | 2,462,363 | — | — | — | — | 2,462,363 |
| Deferred tax liabilities | — | — | 12,576 | — | — | 12,576 |
| Advances from affiliates | — | — | 3,408,659 | — | (3,408,659) | — |
| Other liabilities | 40,840 | — | 188,181 | 197,658 | (167,481) | 259,198 |
| Total liabilities | 3,512,645 | — | 3,875,668 | 225,008 | (3,576,250) | 4,037,071 |
| Mezzanine Capital: | | | | | | |
| Class A Convertible Preferred Units | 761,466 | — | — | — | — | 761,466 |
| Partners' capital, common units | 1,690,799 | — | 2,639,204 | 70,002 | (2,709,206) | 1,690,799 |
| Accumulated other comprehensive income (loss)[1] | — | — | 939 | — | — | 939 |
| Noncontrolling interests | — | — | — | (11,204) | — | (11,204) |
| Total liabilities, mezzanine capital and partners' capital | $5,964,910 | $ — | $6,515,811 | $ 283,806 | $(6,285,456) | $6,479,071 |

[1] The entire balance and activity within Accumulated Other Comprehensive Income is related to our pension held within our Guarantor Subsidiaries.

Table of Contents

Condensed Consolidating Balance Sheet
December 31, 2017

| | Genesis Energy, L.P. (Parent and Co-Issuer) | Genesis Energy Finance Corporation (Co-Issuer) | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Eliminations | Genesis Energy, L.P. Consolidated |
|---|---|---|---|---|---|---|
| ASSETS | | | | | | |
| Current assets: | | | | | | |
| Cash and cash equivalents | $6 | $ — | $8,340 | $695 | $— | $9,041 |
| Other current assets | 50 | — | 614,682 | 12,316 | (56) | 626,992 |
| Total current assets | 56 | — | 623,022 | 13,011 | (56) | 636,033 |
| Fixed Assets, at cost | — | — | 5,523,431 | 77,584 | — | 5,601,015 |
| Less: Accumulated depreciation | — | — | (708,269) | (26,717) | — | (734,986) |
| Net fixed assets | — | — | 4,815,162 | 50,867 | — | 4,866,029 |
| Mineral Leaseholds, net of accumulated depletion | — | — | 564,506 | — | — | 564,506 |
| Goodwill | — | — | 325,046 | — | — | 325,046 |
| Other assets, net | 14,083 | — | 378,371 | 126,300 | (154,437) | 364,317 |
| Advances to affiliates | 3,808,712 | — | — | 85,423 | (3,894,135) | — |
| Equity investees | — | — | 381,550 | — | — | 381,550 |
| Investments in subsidiaries | 2,689,861 | — | 82,616 | — | (2,772,477) | — |
| Total assets | $6,512,712 | $ — | $7,170,273 | $275,601 | $(6,821,105) | $7,137,481 |
| LIABILITIES AND CAPITAL | | | | | | |
| Current liabilities | $46,086 | $ — | $399,017 | $11,417 | $(256) | $456,264 |
| Senior secured credit facility | 1,099,200 | — | — | — | — | 1,099,200 |
| Senior unsecured notes, net of debt issuance costs | 2,598,918 | — | — | — | — | 2,598,918 |
| Deferred tax liabilities | — | — | 11,913 | — | — | 11,913 |
| Advances from affiliates | — | — | 3,894,027 | — | (3,894,027) | — |
| Other liabilities | 45,210 | — | 182,414 | 183,237 | (154,290) | 256,571 |
| Total liabilities | 3,789,414 | — | 4,487,371 | 194,654 | (4,048,573) | 4,422,866 |
| Mezzanine Capital | | | | | | |
| Class A Convertible Preferred Units | 697,151 | — | — | — | — | 697,151 |
| Partners' capital | 2,026,147 | — | 2,683,506 | 89,026 | (2,772,532) | 2,026,147 |
| Accumulated other comprehensive income (loss) | — | — | (604) | — | — | (604) |
| Noncontrolling interests | — | — | — | (8,079) | — | (8,079) |
| Total liabilities, mezzanine capital and partners' capital | $6,512,712 | $ — | $7,170,273 | $275,601 | $(6,821,105) | $7,137,481 |

Table of Contents

Condensed Consolidating Statement of Operations
Year Ended December 31, 2018

| | Genesis Energy, L.P. (Parent and Co-Issuer) | Genesis Energy Finance Corporation (Co-Issuer) | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Eliminations | Genesis Energy, L.P. Consolidated |
|---|---|---|---|---|---|---|
| REVENUES: | | | | | | |
| Offshore pipeline transportation services | $ — | $ — | $ 284,544 | $ — | $ — | $ 284,544 |
| Sodium minerals and sulfur services | — | — | 1,171,913 | 11,113 | (8,592 ) | 1,174,434 |
| Marine transportation | — | — | 219,937 | — | — | 219,937 |
| Onshore facilities and transportation | — | — | 1,214,235 | 19,620 | — | 1,233,855 |
| Total revenues | — | — | 2,890,629 | 30,733 | (8,592 ) | 2,912,770 |
| COSTS AND EXPENSES: | | | | | | |
| Onshore facilities and transportation costs | — | — | 1,125,528 | 1,202 | — | 1,126,730 |
| Marine transportation operating costs | — | — | 172,527 | — | — | 172,527 |
| Sodium minerals and sulfur services operating costs | — | — | 911,135 | 9,948 | (8,592 ) | 912,491 |
| Offshore pipeline transportation operating costs | — | — | 64,272 | 2,396 | — | 66,668 |
| General and administrative | — | — | 66,898 | — | — | 66,898 |
| Depreciation, depletion and amortization | — | — | 310,690 | 2,500 | — | 313,190 |
| Gain on sale of assets | — | — | (42,264 ) | — | — | (42,264 ) |
| Impairment expense | — | — | 100,093 | 26,189 | — | 126,282 |
| Total costs and expenses | — | — | 2,708,879 | 42,235 | (8,592 ) | 2,742,522 |
| OPERATING INCOME | — | — | 181,750 | (11,502 ) | — | 170,248 |
| Equity in earnings of equity investees | — | — | 43,626 | — | — | 43,626 |
| Equity in earnings of subsidiaries | 219,615 | — | (18,564 ) | — | (201,051 ) | — |
| Interest expense, net | (230,713 ) | — | 14,706 | (13,184 ) | — | (229,191 ) |
| Other income | 5,023 | — | — | — | — | 5,023 |
| Income before income taxes | (6,075 ) | — | 221,518 | (24,686 ) | (201,051 ) | (10,294 ) |
| Income tax benefit (expense) | — | — | (1,727 ) | 229 | — | (1,498 ) |
| NET INCOME (LOSS) | (6,075 ) | — | 219,791 | (24,457 ) | (201,051 ) | (11,792 ) |
| Net loss attributable to noncontrolling interests | — | — | — | 5,717 | — | 5,717 |
| NET INCOME (LOSS) ATTRIBUTABLE TO GENESIS ENERGY, L.P. | $ (6,075 ) | $ — | $ 219,791 | $ (18,740 ) | $ (201,051 ) | $ (6,075 ) |
| Less: Accumulated distributions attributable to Class A Convertible Preferred Units | (69,801 ) | — | — | — | — | (69,801 ) |
| NET INCOME (LOSS) AVAILABLE TO COMMON UNIT HOLDERS | $ (75,876 ) | $ — | $ 219,791 | $ (18,740 ) | $ (201,051 ) | $ (75,876 ) |

Table of Contents

Condensed Consolidating Statement of Operations
Year Ended December 31, 2017

| | Genesis Energy, L.P. (Parent and Co-Issuer) | Genesis Energy Finance Corporation (Co-Issuer) | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Eliminations | Genesis Energy, L.P. Consolidated |
|---|---|---|---|---|---|---|
| REVENUES: | | | | | | |
| Offshore pipeline transportation services | $ — | $ — | $ 318,239 | | $ — | $ 318,239 |
| Sodium minerals and sulfur services | — | — | 460,790 | 9,252 | (7,420) | 462,622 |
| Marine transportation | — | — | 205,287 | — | — | 205,287 |
| Onshore facilities and transportation | — | — | 1,023,293 | 18,936 | — | 1,042,229 |
| Total revenues | — | — | 2,007,609 | 28,188 | (7,420) | 2,028,377 |
| COSTS AND EXPENSES: | | | | | | |
| Onshore facilities and transportation costs | — | — | 967,558 | 1,089 | — | 968,647 |
| Marine transportation operating costs | — | — | 154,606 | — | — | 154,606 |
| Sodium minerals and sulfur services operating costs | — | — | 332,209 | 9,129 | (7,420) | 333,918 |
| Offshore pipeline transportation operating costs | — | — | 69,225 | 2,840 | — | 72,065 |
| General and administrative | — | — | 66,421 | — | — | 66,421 |
| Depreciation, depletion and amortization | — | — | 249,980 | 2,500 | — | 252,480 |
| Gain on sale of assets | — | — | (40,311) | — | — | (40,311) |
| Total costs and expenses | — | — | 1,799,688 | 15,558 | (7,420) | 1,807,826 |
| OPERATING INCOME | — | — | 207,921 | 12,630 | — | 220,551 |
| Equity in earnings of equity investees | — | — | 51,046 | — | — | 51,046 |
| Equity in earnings of subsidiaries | 276,341 | — | (520) | — | (275,821) | — |
| Interest expense, net | (176,979) | — | 14,122 | (13,905) | — | (176,762) |
| Other expense | (16,715) | — | — | — | — | (16,715) |
| Income before income taxes | 82,647 | — | 272,569 | (1,275) | (275,821) | 78,120 |
| Income tax expense | — | — | 3,928 | 31 | — | 3,959 |
| NET INCOME | 82,647 | — | 276,497 | (1,244) | (275,821) | 82,079 |
| Net loss attributable to noncontrolling interests | — | — | — | 568 | — | 568 |
| NET INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P. | $ 82,647 | $ — | $ 276,497 | $ (676) | $ (275,821) | $ 82,647 |
| Less: Accumulated distributions attributable to Class A Convertible Preferred Units | (21,995) | — | — | — | — | (21,995) |
| NET INCOME AVAILABLE TO COMMON UNIT HOLDERS | $ 60,652 | $ — | $ 276,497 | $ (676) | $ (275,821) | $ 60,652 |

Table of Contents

Condensed Consolidating Statement of Operations
Year Ended December 31, 2016

| | Genesis Energy, L.P. (Parent and Co-Issuer) | Genesis Energy Finance Corporation (Co-Issuer) | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Eliminations | Genesis Energy, L.P. Consolidated |
|---|---|---|---|---|---|---|
| REVENUES: | | | | | | |
| Offshore pipeline transportation services | $ — | $ — | $ 334,679 | | $ — | $ 334,679 |
| Sodium minerals and sulfur services | — | — | 171,389 | 7,873 | (7,759 ) | 171,503 |
| Marine transportation | — | — | 213,021 | — | — | 213,021 |
| Onshore facilities and transportation | — | — | 972,794 | 20,496 | — | 993,290 |
| Total revenues | — | — | 1,691,883 | 28,369 | (7,759 ) | 1,712,493 |
| COSTS AND EXPENSES: | | | | | | |
| Onshore facilities and transportation costs | — | — | 923,567 | 1,060 | — | 924,627 |
| Marine transportation operating costs | — | — | 142,551 | — | — | 142,551 |
| Sodium minerals and sulfur services operating costs | — | — | 90,711 | 8,491 | (7,759 ) | 91,443 |
| Offshore pipeline transportation operating costs | — | — | 68,791 | 10,833 | — | 79,624 |
| General and administrative | — | — | 45,625 | — | — | 45,625 |
| Depreciation and amortization | — | — | 219,696 | 2,500 | — | 222,196 |
| Total costs and expenses | — | — | 1,490,941 | 22,884 | (7,759 ) | 1,506,066 |
| OPERATING INCOME | — | — | 200,942 | 5,485 | — | 206,427 |
| Equity in earnings of equity investees | — | — | 47,944 | — | — | 47,944 |
| Equity in earnings of subsidiaries | 253,048 | — | (6,744 ) | — | (246,304 ) | — |
| Interest expense, net | (139,799 ) | — | 14,407 | (14,555 ) | — | (139,947 ) |
| Income before income taxes | 113,249 | — | 256,549 | (9,070 ) | (246,304 ) | 114,424 |
| Income tax expense | — | — | (3,337 ) | (5 ) | — | (3,342 ) |
| NET INCOME | $ 113,249 | $ — | $ 253,212 | $ (9,075 ) | $ (246,304 ) | $ 111,082 |
| Net loss attributable to noncontrolling interest | $ — | $ — | $ — | $ 2,167 | $ — | 2,167 |
| NET INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P. | $ 113,249 | $ — | $ 253,212 | $ (6,908 ) | $ (246,304 ) | $ 113,249 |
| Less: Accumulated distributions attributable to Class A Convertible Preferred Units | $ — | $ — | $ — | $ — | $ — | — |
| NET INCOME AVAILABLE TO COMMON UNIT HOLDERS | $ 113,249 | $ — | $ 253,212 | $ (6,908 ) | $ (246,304 ) | $ 113,249 |

Table of Contents

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2018

| | Genesis Energy, L.P. (Parent and Co-Issuer) | Genesis Energy Finance Corporation (Co-Issuer) | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Eliminations | Genesis Energy, L.P. Consolidated |
|---|---|---|---|---|---|---|
| Net cash (used in) provided by operating activities | $ 28,784 | $ — | $ 595,510 | $ 2,556 | $ (236,811 ) | $ 390,039 |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | | | | | |
| Payments to acquire fixed and intangible assets | — | — | (195,367 ) | — | — | (195,367 ) |
| Cash distributions received from equity investees - return of investment | — | — | 28,979 | — | — | 28,979 |
| Investments in equity investees | — | — | (3,018 ) | — | — | (3,018 ) |
| Intercompany transfers | 503,144 | — | — | — | (503,144 ) | — |
| Repayments on loan to non-guarantor subsidiary | — | — | 7,484 | — | (7,484 ) | — |
| Proceeds from asset sales | — | — | 310,099 | — | — | 310,099 |
| Net cash provided by (used in) provided by investing activities | 503,144 | — | 148,177 | — | (510,628 ) | 140,693 |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | | | | | |
| Borrowings on senior secured credit facility | 980,700 | — | — | — | — | 980,700 |
| Repayments on senior secured credit facility | (1,109,800 ) | — | — | — | — | (1,109,800 ) |
| Repayment of senior unsecured notes | (145,170 ) | — | — | — | — | (145,170 ) |
| Debt issuance costs | (242 ) | — | — | — | — | (242 ) |
| Intercompany transfers | — | — | (485,506 ) | (17,638 ) | 503,144 | — |
| Distributions to partners/owners | (257,416 ) | — | (257,416 ) | — | 257,416 | (257,416 ) |
| Contributions from noncontrolling interest | — | — | — | 2,592 | — | 2,592 |
| Other, net | — | — | (137 ) | 13,121 | (13,121 ) | (137 ) |
| Net cash provided by (used in) financing activities | (531,928 ) | — | (743,059 ) | (1,925 ) | 747,439 | (529,473 ) |
| Net increase in cash and cash equivalents | — | — | 628 | 631 | — | 1,259 |
| Cash and cash equivalents at beginning of period | 6 | — | 8,340 | 695 | — | 9,041 |
| Cash and cash equivalents at end of period | $ 6 | $ — | $ 8,968 | $ 1,326 | $ — | $ 10,300 |

Table of Contents

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2017

| | Genesis Energy, L.P. (Parent and Co-Issuer) | Genesis Energy Finance Corporation (Co-Issuer) | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Eliminations | Genesis Energy, L.P. Consolidated |
|---|---|---|---|---|---|---|
| Net cash (used in) provided by operating activities | $162,980 | $ — | $466,425 | $ (4,585 ) | $(301,264 ) | $323,556 |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | | | | | |
| Payments to acquire fixed and intangible assets | — | — | (250,593 ) | — | — | (250,593 ) |
| Cash distributions received from equity investees - return of investment | — | — | 35,582 | — | — | 35,582 |
| Investments in equity investees | (140,513 ) | — | (4,647 ) | — | 140,513 | (4,647 ) |
| Acquisitions | — | — | (1,325,759) | — | — | (1,325,759 ) |
| Intercompany transfers | (1,157,781) | — | — | — | 1,157,781 | — |
| Repayments on loan to non-guarantor subsidiary | — | — | 6,764 | — | (6,764 ) | — |
| Contributions in aid of construction costs | — | — | 124 | — | — | 124 |
| Proceeds from assets sales | — | — | 85,722 | — | — | 85,722 |
| Net cash (used in) provided by investing activities | (1,298,294) | — | (1,452,807) | — | 1,291,530 | (1,459,571 ) |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | | | | | |
| Borrowings on senior secured credit facility | 1,458,700 | — | — | — | — | 1,458,700 |
| Repayments on senior secured credit facility | (1,637,700) | — | — | — | — | (1,637,700 ) |
| Proceeds from issuance of senior unsecured notes, including premium | 1,000,000 | — | — | — | — | 1,000,000 |
| Proceeds from issuance of Series A convertible preferred | 726,419 | — | — | — | — | 726,419 |
| Repayment of senior unsecured notes | (204,830 ) | — | — | — | — | (204,830 ) |
| Debt issuance costs | (25,913 ) | — | — | — | — | (25,913 ) |
| Intercompany transfers | — | — | 1,169,781 | (12,000 ) | (1,157,781 ) | — |
| Issuance of common units for cash, net | 140,513 | — | 140,513 | — | (140,513 ) | 140,513 |
| Distributions to partners/owners | (321,875 ) | — | (321,875 ) | — | 321,875 | (321,875 ) |
| Contributions from noncontrolling interest | — | — | — | 2,770 | — | 2,770 |
| Other, net | — | — | (57 ) | 13,847 | (13,847 ) | (57 ) |
| Net cash provided by (used in) financing activities | 1,135,314 | — | 988,362 | 4,617 | (990,266 ) | 1,138,027 |
| Net increase in cash and cash equivalents | — | — | 1,980 | 32 | — | 2,012 |
| Cash and cash equivalents at beginning of period | 6 | — | 6,360 | 663 | — | 7,029 |
| Cash and cash equivalents at end of period | $6 | $ — | $8,340 | $ 695 | $— | $9,041 |

F-57

Table of Contents

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2016

| | Genesis Energy, L.P. (Parent and Co-Issuer) | Genesis Energy Finance Corporation (Co-Issuer) | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Eliminations | Genesis Energy, L.P. Consolidated |
|---|---|---|---|---|---|---|
| Net cash (used in) provided by operating activities | $179,853 | $ — | $382,734 | $ 9,586 | $(289,421) | $282,752 |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | | | | | |
| Payments to acquire fixed and intangible assets | — | — | (463,100) | — | — | (463,100) |
| Cash distributions received from equity investees - return of investment | — | — | 36,939 | — | — | 36,939 |
| Investments in equity investees | (298,020) | — | — | — | 298,020 | — |
| Acquisitions | — | — | (25,394) | — | — | (25,394) |
| Intercompany transfers | (31,436) | — | — | — | 31,436 | — |
| Repayments on loan to non-guarantor subsidiary | — | — | 6,113 | — | (6,113) | — |
| Contributions in aid of construction costs | — | — | 13,374 | — | — | 13,374 |
| Proceeds from asset sales | — | — | 3,609 | — | — | 3,609 |
| Other, net | — | — | (151) | — | — | (151) |
| Net cash (used in) provided by investing activities | (329,456) | — | (428,610) | — | 323,343 | (434,723) |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | | | | | |
| Borrowings on senior secured credit facility | 1,115,800 | — | — | — | — | 1,115,800 |
| Repayments on senior secured credit facility | (952,600) | — | — | — | — | (952,600) |
| Debt issuance costs | (1,578) | — | — | — | — | (1,578) |
| Distribution to partners/owners | (310,039) | — | (310,039) | — | 310,039 | (310,039) |
| Contributions from noncontrolling interest | — | — | — | 236 | — | 236 |
| Issuance of common units for cash, net | 298,020 | — | 298,020 | — | (298,020) | 298,020 |
| Intercompany transfers | — | — | 57,701 | (26,264) | (31,437) | — |
| Other, net | — | — | (1,734) | 14,504 | (14,504) | (1,734) |
| Net cash provided by (used in) financing activities | 149,603 | — | 43,948 | (11,524) | (33,922) | 148,105 |
| Net decrease in cash and cash equivalents | — | — | (1,928) | (1,938) | — | (3,866) |
| Cash and cash equivalents at beginning of period | 6 | — | 8,288 | 2,601 | — | 10,895 |
| Cash and cash equivalents at end of period | $6 | $ — | $6,360 | $ 663 | $— | $7,029 |

F-58

Table of Contents

## Report of Independent Auditors

The Management Committee
Poseidon Oil Pipeline Company, L.L.C.

We have audited the accompanying financial statements of Poseidon Oil Pipeline Company, L.L.C. which comprise the balance sheets as of December 31, 2018 and 2017, and the related statements of operations, cash flows, and members' equity (deficit) for the years then ended, and the related notes to the financial statements.

### Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in conformity with U.S. generally accepted accounting principles; this includes the design, implementation and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free of material misstatement, whether due to fraud or error.

### Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

### Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Poseidon Oil Pipeline Company, L.L.C. at December 31, 2018 and 2017, and the results of its operations and its cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP
Houston, Texas
February 19, 2019

Table of Contents

# INDEPENDENT AUDITORS' REPORT

To the Management Committee of
Poseidon Oil Pipeline Company, L.L.C.
Houston, Texas

We have audited the accompanying statements of operations, cash flows, and members' equity of Poseidon Oil Pipeline Company, L.L.C. (the "Company") for the year ended December 31, 2016, and the related notes to the financial statements.

## Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

## Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

## Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the results of operations and cash flows of Poseidon Oil Pipeline Company, L.L.C. for the year ended December 31, 2016 in accordance with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
February 17, 2017

F-60

Table of Contents

POSEIDON OIL PIPELINE COMPANY, L.L.C.
BALANCE SHEETS
(In thousands)

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| ASSETS | | |
| CURRENT ASSETS: | | |
| Cash and cash equivalents | $261 | $132 |
| Accounts receivable—trade | 15,578 | 14,443 |
| Accounts receivable—related parties | 1,189 | 1,121 |
| Crude oil inventory | 1,565 | 2,691 |
| Other current assets | 318 | 324 |
| Total current assets | 18,911 | 18,711 |
| FIXED ASSETS, net | 202,116 | 217,343 |
| OTHER ASSETS | 886 | 1,203 |
| TOTAL ASSETS | $221,913 | $237,257 |
| LIABILITIES AND MEMBERS’ EQUITY | | |
| CURRENT LIABILITIES: | | |
| Accounts payable – trade | $2,548 | $1,757 |
| Accounts payable – related parties | 2,664 | 2,384 |
| Deferred revenue | 9,187 | 11,357 |
| Other current liabilities | 1,510 | 2,062 |
| Total current liabilities | 15,909 | 17,560 |
| LONG-TERM DEBT | 208,300 | 206,600 |
| OTHER LIABILITIES | 34,581 | 30,834 |
| MEMBERS' EQUITY (DEFICIT) | (36,877) | (17,737) |
| TOTAL LIABILITIES AND MEMBERS' EQUITY | $221,913 | $237,257 |

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

Table of Contents

POSEIDON OIL PIPELINE COMPANY, L.L.C.
STATEMENTS OF OPERATIONS
(In thousands, except per unit amounts)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| CRUDE OIL HANDLING REVENUES: | | | |
| Third parties | $99,356 | $98,024 | $100,383 |
| Related parties | 16,139 | 19,109 | 19,899 |
| Total crude oil handling revenues | 115,495 | 117,133 | 120,282 |
| COSTS AND EXPENSES: | | | |
| Crude oil handling costs | | | |
| Third parties | 2,470 | 1,774 | 1,989 |
| Related parties | 6,345 | 5,889 | 3,788 |
| Total crude oil handling costs | 8,815 | 7,663 | 5,777 |
| Other operating costs and expenses | | | |
| Third parties | 823 | 852 | 1,238 |
| Related parties | 8,640 | 8,388 | 7,914 |
| Total other operating costs and expenses | 9,463 | 9,240 | 9,152 |
| Depreciation and accretion expenses | 16,218 | 15,633 | 15,615 |
| General and administrative costs | 65 | 45 | 101 |
| Total costs and expenses | 34,561 | 32,581 | 30,645 |
| OPERATING INCOME | 80,934 | 84,552 | 89,637 |
| Interest expense | 7,974 | 6,026 | 4,729 |
| NET INCOME | $72,960 | $78,526 | $84,908 |

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

Table of Contents

POSEIDON OIL PIPELINE COMPANY, L.L.C.
STATEMENTS OF CASH FLOWS
(In thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| CASH FLOWS FROM OPERATING ACTIVITIES: | | | |
| Net income | $72,960 | $78,526 | $84,908 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization and accretion expenses | 16,490 | 15,905 | 15,887 |
| Effect of changes in operating accounts: | | | |
| Accounts receivable | (1,203) | (687) | 2,139 |
| Inventories | 1,201 | (1,230) | (887) |
| Other current assets | 51 | (261) | (379) |
| Accounts payable | 1,062 | (1,434) | 409 |
| Other liabilities | 332 | 11,334 | 9,082 |
| Net cash provided by operating activities | 90,893 | 102,153 | 111,159 |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | | |
| Additions to fixed assets | (364) | (66) | (183) |
| Net cash used in investing activities | (364) | (66) | (183) |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | | |
| Borrowings under revolving credit facility | 71,900 | 84,200 | 85,900 |
| Repayments of principal | (70,200) | (79,650) | (81,100) |
| Cash distributions to Members | (92,100) | (106,600) | (116,300) |
| Net cash used in financing activities | (90,400) | (102,050) | (111,500) |
| Net increase (decrease) in cash and cash equivalents | 129 | 37 | (524) |
| Cash and cash equivalents at beginning of period | 132 | 95 | 619 |
| Cash and cash equivalents at end of period | $261 | $132 | $95 |
| | | | |
| SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION | | | |
| Cash paid during the year for interest | $7,544 | $5,698 | $4,402 |
| Current liabilities for capital expenditures at end of year | $10 | $57 | $— |

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

Table of Contents

POSEIDON OIL PIPELINE COMPANY, L.L.C.
STATEMENT OF MEMBERS' EQUITY (DEFICIT)
(In thousands)

| | Poseidon Pipeline Company, L.L.C. | Shell Midstream Partners, L.P. | GEL Poseidon, LLC | Total |
|---|---|---|---|---|
| January 1, 2016 | 15,022 | $ 15,022 | $ 11,685 | $ 41,729 |
| Net income | 30,567 | 30,567 | 23,774 | $ 84,908 |
| Cash distributions to members | (41,868 ) | (41,868 ) | (32,564 ) | $ (116,300) |
| December 31, 2016 | 3,721 | 3,721 | 2,895 | 10,337 |
| Net income | 28,269 | 28,269 | 21,988 | $ 78,526 |
| Cash distributions to members | (38,376 ) | (38,376 ) | (29,848 ) | $ (106,600) |
| December 31, 2017 | (6,386 ) | (6,386 ) | (4,965 ) | (17,737 ) |
| Net income | 26,266 | 26,266 | 20,428 | $ 72,960 |
| Cash distributions to members | (33,156 ) | (33,156 ) | (25,788 ) | $ (92,100 ) |
| December 31, 2018 | $ (13,276 ) | $ (13,276 ) | $ (10,325) | $ (36,877 ) |

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

POSEIDON OIL PIPELINE COMPANY, L.L.C.
NOTES TO FINANCIAL STATEMENTS

Note 1. Company Organization and Description of Business

Company Organization
Poseidon Oil Pipeline Company, L.L.C. (“Poseidon”) is a Delaware limited liability company formed in February 1996 to design, construct, own and operate an unregulated crude oil pipeline system located in the central Gulf of Mexico offshore Louisiana. Unless the context requires otherwise, references to “we”, “us”, “our” or “the Company” within these notes are intended to mean Poseidon.

At December 31, 2018, we were owned (i) 36% by Poseidon Pipeline Company, L.L.C. and (ii) 28% by GEL Poseidon, LLC, collectively ("Genesis") and (iii) 36% by Shell Midstream Partners, L.P. (“Shell”).

Description of Business
The Poseidon Oil Pipeline System (the “Pipeline”) gathers crude oil production from the outer continental shelf and deep-water areas of the Gulf of Mexico offshore Louisiana for delivery to onshore locations in south Louisiana. The system includes a pipeline junction platform located at South Marsh Island 205 (“SMI-205”). Manta Ray Gathering Company, L.L.C. (“Manta Ray”), a wholly owned subsidiary of Genesis acquired as part of Enterprise’s offshore business, serves as operator of the Pipeline.

Note 2. Significant Accounting Policies

Our financial statements are prepared on the accrual basis of accounting in accordance with U.S. generally accepted accounting principles (“GAAP”).

Except as noted within the context of each footnote disclosure, dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.

In preparing these financial statements, the Company has evaluated subsequent events for potential recognition or disclosure through February 19, 2019, the issuance date of the financial statements.

Cash and Cash Equivalents
Cash and cash equivalents represent unrestricted cash on hand and may also include highly liquid investments with original maturities of less than three months from the date of purchase.

Accounts Receivable
We review our outstanding accounts receivable balances on a regular basis and record an allowance for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted.

Contingency and Liability Accruals
We accrue reserves for contingent liabilities including environmental remediation and potential legal claims. When our assessment indicates that it is probable that a liability has occurred and the amount of the liability can be reasonably estimated, we make accruals. We base our estimates on all known facts at the time and our assessment of the ultimate outcome, including consultation with external experts and counsel. We revise these estimates as additional information is obtained or resolution is achieved.

We also make estimates related to future payments for environmental costs to remediate existing conditions attributable to past operations. Environmental costs include costs for studies and testing as well as remediation and restoration. We sometimes make these estimates with the assistance of third parties involved in monitoring the remediation effort.

At December 31, 2018, we were not aware of any contingencies or liabilities that would have a material effect on our financial position, results of operations or cash flows.

Crude Oil Handling Costs

Crude oil handling costs represent expenses we incur as a result of utilizing third party-owned and related party-owned pipelines in the provision of services.

Table of Contents

Estimates
Preparing our financial statements in conformity with GAAP requires us to make estimates that affect amounts presented in the financial statements. Our most significant estimates relate to (i) the useful lives and depreciation methods used for fixed assets; (ii) measurement of fair value and projections used in impairment testing of fixed assets; (iii) contingencies; (iv) revenue and expense accruals; and (v) estimates of future asset retirement obligations.

Actual results could differ materially from our estimates. On an ongoing basis, we review our estimates based on currently available information. Any changes in the facts and circumstances underlying our estimates may require us to update such estimates, which could have a material impact on our financial statements.

Fair Value Information
The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair values based on their short-term nature. The fair value of the amounts outstanding under the February 2015 Credit Facility approximate book value as of December 31, 2018 given the variable rate nature of this debt.

Impairment Testing for Long-Lived Assets
Long-lived assets such as fixed assets are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. Long-lived assets with carrying values that are not expected to be recovered through future cash flows are written-down to their estimated fair values. The carrying value of a long-lived asset is deemed not recoverable if it exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset’s carrying value exceeds the sum of its undiscounted cash flows, a non-cash asset impairment charge equal to the excess of the asset’s carrying value over its estimated fair value is recorded. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. We measure fair value using market price indicators or, in the absence of such data, appropriate valuation techniques.

No asset impairment charges were recognized during the years ended December 31, 2018, 2017 or 2016.

Income Taxes
We are organized as a pass-through entity for federal income tax purposes. As a result, our financial statements do not provide for such taxes and our Members are individually responsible for their allocable share of our taxable income for federal income tax purposes.

Inventories
We take title to crude oil volumes we purchase from producers and volumes we obtain through contractual pipeline loss allowances. Timing and measurement differences between receipt and delivery volumes, as well as fluctuations in crude oil pricing, impact our inventory balances. Our inventory amounts are presented at the lower of average cost or market.

Due to fluctuating crude oil prices, we recognize lower of cost or market adjustments when the carrying value of our crude oil inventory exceeds its net realizable value. These non-cash charges are a component of “Crude oil handling costs” on our Statement of Operations in the period they are recognized. We recognized $0.1 million, $0.1 million and $0.0 million of lower of cost or net realizable value adjustments during 2018, 2017 and 2016, respectively.

Fixed Assets and Asset Retirement Obligations
Fixed assets are recorded at cost. Expenditures for additions, improvements and other enhancements to fixed assets are capitalized, and minor replacements, maintenance, and repairs that do not extend asset life or add value are charged to expense as incurred. When fixed assets are retired or otherwise disposed of, the related cost and accumulated depreciation is removed from the accounts and any resulting gain or loss is included in results of

operations for the respective period.

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the reporting periods it benefits. Our fixed assets are depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of an asset. Our estimate of depreciation expense incorporates management assumptions regarding the useful economic lives and residual values of our assets. Estimated useful lives are 5 to 30 years for our related fixed assets.

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of tangible long-lived assets that result from their acquisition, construction, development and/or normal operation. When an ARO is incurred, we record a liability for the ARO and capitalize an equal amount as an increase in the carrying value of the related long-lived asset. ARO amounts are measured at their estimated fair value using expected present value techniques. Over time, the liability is accreted to its present value (through accretion expense) and the capitalized amount is depreciated over the remaining useful life of the related long-

Table of Contents

term asset. We will incur a gain or loss to the extent that our ARO liabilities are not settled at their recorded amounts. See Note 3 for additional information regarding our fixed assets and related AROs.

Revenue Recognition

Crude oil handling revenues are generated from purchase and sale agreements whereby we purchase crude oil from producers at various receipt points along the Pipeline for a contractual fixed price (less a “handling fee”) and sell common stream crude oil back to the producers at various redelivery points at the same contractual fixed price (before the handling fee was applied). Since these purchase and sale transactions are with the same customer and entered into in contemplation of one another, the purchase and sales amounts are netted against one another and the residual handling fees are recognized as crude oil handling revenue. The intent of these buy-sell arrangements is to earn a fee for handling crude oil (a service to the producer) and not to engage in crude oil marketing activities. We also net the corresponding receivables and payables from such transactions on our Balance Sheets for consistency of presentation.

We have entered into long-term pipeline capacity reservation agreements with Anadarko Petroleum Corporation, Eni Petroleum Co. Inc., Exxon Mobil Corporation, Freeport-McMoran Inc., Petrobras America Inc., and Teikoku Oil (North America) Co., Ltd., collectively the “Lucius producers”. The term of these agreements is 20 years (July 2014 through June 2034), which corresponds to the period of dedicated production from the Lucius producers under the agreements. The amount of pipeline capacity reserved each year for the Lucius producers is based on their expected production volumes for that period (as defined in the contract). The capacity reservation agreements require the Lucius producers to make scheduled minimum bill payments to us (as defined in the contract). We defer that portion of the minimum bill payments that relate to future performance obligations under the contract. We recognized $10.8 million, $13.3 million and $13.3 million of pipeline capacity reservation revenues from the Lucius producers for the years ended December 31, 2018, 2017, and 2016, respectively. At December 31, 2018 our deferred revenue attributable to the Lucius agreements totaled $41.1 million of which $9.2 million is expected to be recognized as revenue in 2019.

Recent and Proposed Accounting Pronouncements

In May 2014, the FASB issued revised guidance on revenue from contracts with customers that will supersede most current revenue recognition guidance, including industry-specific guidance. The core principle of the revenue model is that an entity will recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The new standard provides a five-step analysis for transactions to determine when and how revenue is recognized. The guidance permits the use of either a full retrospective or a modified retrospective approach. In July 2015, the FASB approved a one year deferral of the effective date of this standard to December 15, 2017 for annual reporting periods beginning after that date for public companies, or December 15, 2018 for all other entities. We have elected to adopt the new standard for the annual reporting period following December 15, 2018. We will adopt this guidance as of January 1, 2019 using the modified retrospective approach and will not have a material cumulative adjustment as a result of the adoption.

In February 2016, the FASB issued guidance to improve the transparency and comparability among companies by requiring lessees to recognize a lease liability and a corresponding lease asset for virtually all lease contracts. The guidance also requires additional disclosure about leasing arrangements. The guidance is effective for interim and annual periods beginning after December 15, 2018 for public entities and December 15, 2019 for non-public entities. We have elected to adopt the new standard for the annual reporting period following December 15, 2019. We are currently evaluating the impacts of our pending adoption of this guidance.

In August 2016, the FASB issued guidance that addresses how certain cash receipts and payments are presented and classified in the statement of cash flows under Topic 230, Statement of Cash flow, and other Topics. The guidance is effective for annual reporting periods, and interim periods therein, beginning after December 15, 2017. We have adopted this guidance as of January 1, 2018 with no material impact on our financial statements.

Table of Contents

Note 3. Fixed Assets and Asset Retirement Obligations

Fixed Assets
Our fixed asset values and related accumulated depreciation balances were as follows at the dates indicated:

| | At December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Pipelines and facilities | $433,560 | $433,174 | $433,105 |
| Construction in progress | — | 87 | 32 |
| Total | 433,560 | 433,261 | 433,137 |
| Less accumulated depreciation | (231,444 ) | (215,918 ) | (200,401 ) |
| Fixed assets, net | $202,116 | $217,343 | $232,736 |

Depreciation expense was $16.9 million, $15.5 million and $15.5 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Asset retirement obligations
Our AROs result from regulatory requirements that would be triggered by the retirement of our offshore pipeline and platform assets. During the third quarter of 2018, we began the abandonment of the ST-204 8” pipeline lateral, which is a part of the Poseidon Oil Pipeline system, after being notified that the owner of the ST-204 platform complex would be removing their assets from the production area. Due to this we revised the timing of the expected retirement obligation as it relates to the ST-204 lateral pipeline. During the fourth quarter of 2018, the abandonment of the ST-204 8” pipeline lateral was completed. No other revisions to the estimated retirement obligation were made during the period. The following table presents information regarding our estimable asset retirement liabilities for the periods noted.

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| ARO liability, beginning of period | $1,629 | $1,513 | $1,405 |
| Liabilities settled | (604 ) | — | — |
| Accretion expense | 127 | 116 | 108 |
| Revisions in expected cash flows | 1,341 | — | — |
| Gain on settlement | (775 ) | — | — |
| ARO liability, end of period | $1,718 | $1,629 | $1,513 |

The ARO liability is included in "Other liabilities" in our December 31, 2018 and December 31, 2017 Balance Sheet. Cash settlements of the ARO obligation are recorded in "Other Liabilities" within the Operating Activities in the Statements of Cash Flows.

At December 31, 2018, our forecast of accretion expense is as follows for the next five years:

| 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|
| $133 | $143 | $154 | $166 | $179 |

Note 4. Debt Obligation

February 2015 Credit Facility

In February 2015, we entered into an amended and restated revolving credit agreement having an initial borrowing capacity of $225 million, with a provision that its borrowing capacity could be expanded to $275 million with additional commitments from the lenders. Amounts borrowed under the February 2015 credit facility mature in February 2020. We used $186.8 million of borrowing capacity under the new credit facility to refinance principal amounts that were outstanding under the April 2011 Credit

Table of Contents

Facility at termination. We incurred $1.3 million of debt issuance costs related to the February 2015 Credit Facility of which $0.3 million and $0.6 million is deferred within other assets on our Balance Sheet at December 31, 2018 and 2017, respectively.

The weighted-average variable interest rate charged under the February 2015 credit facility was approximately 3.8% and 2.8% for the years ended December 31, 2018 and 2017, respectively. Interest rates charged under the 2015 credit facility are dependent on certain quarterly financial ratios (as defined in the credit agreement). For Eurodollar loans where our leverage ratio is greater than or equal to 1:1 and less than 2:1, the interest rate is the London Interbank Offered Rate ("LIBOR") plus 1.75%, and for Base Rate loans (as defined in the credit agreement), the interest rate is 0.75% plus a variable base rate equal to the greater of (i) the prime rate, (ii) the federal funds rate plus 0.50% or (iii) LIBOR plus 1.00%. The interest rate on Eurodollar and Base Rate loans would increase by 0.25% if our leverage ratio increased to greater than 2:1 and would decrease by 0.25% if our leverage ratio decreased to less than or equal to 1:1. In addition, we pay commitment fees on the unused portion of the revolving credit facility at rates that vary from 0.25% to 0.375%.

The February 2015 credit facility is non-recourse to our Members and secured by our assets. The February 2015 credit facility also contains customary covenants such as restrictions on debt levels, liens, guarantees, mergers, sale of assets and distributions to Members. A breach of any of these covenants could result in acceleration of our debt financial obligations. We were in compliance with the covenants of our credit facility at December 31, 2018.

In general, if an Event of Loss occurs (as defined in the credit agreement), we are obligated to either repair the damage or use any insurance proceeds we receive to reduce debt principal outstanding.

Note 5. Members' Equity

As a limited liability company, our Members are not personally liable for any of our debts, obligations or other liabilities. Income or loss amounts are allocated to Members based on their respective membership interests. Cash contributions by and distributions to Members are also based on their respective membership interests.

Cash distributions to Members are determined by our Management Committee, which is responsible for conducting the Company's affairs in accordance with our limited liability agreement.

Note 6. Related Party Transactions

The following table summarizes our related party transactions for the period indicated:

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Crude oil handling revenues: | | | |
| Genesis affiliates | 994 | 986 | 1,007 |
| Shell affiliates | 15,145 | 18,123 | 18,892 |
| Total | $16,139 | $19,109 | $19,899 |

| | | | |
|---|---|---|---|
| Crude oil handling costs: | | | |
| Genesis affiliates | 3,917 | 3,951 | 2,930 |
| Shell affiliates | 2,428 | 1,938 | 858 |
| Total | $6,345 | $5,889 | $3,788 |
| Other operating costs and expenses: | | | |
| Genesis affiliates | 8,640 | 8,388 | 7,914 |
| Total | $8,640 | $8,388 | $7,914 |

Other operating costs and expenses include amounts charged to us by Manta Ray for operator fees and space on their SS-332A platform.

Table of Contents

The following table summarizes our related party accounts receivable and accounts payable amounts at the dates indicated:

| | At December 31, | |
|---|---|---|
| | 2018 | 2017 |
| Accounts receivable - related parties: | | |
| Genesis affiliates | $— | $— |
| Shell affiliates | 1,189 | 1,121 |
| Total accounts receivable - related parties | $1,189 | $1,121 |
| | | |
| Accounts payable - related parties: | | |
| Genesis affiliates | 2,392 | 2,175 |
| Shell affiliates | 272 | 209 |
| Total accounts payable - related parties | $2,664 | $2,384 |

Note 7. Significant Risks

Production and Credit Risk due to Customer Concentration
Offshore pipeline systems such as ours are directly impacted by exploration and production activities in the Gulf of Mexico for crude oil. Crude oil reserves are depleting assets. Our crude oil pipeline system must access additional reserves to offset either (i) the natural decline in production from existing connected wells or (ii) the loss of production to a competing takeaway pipeline. We actively seek to offset the loss of volumes due to depletion by adding connections to new customers and production fields.

In terms of percentage of total revenues, our largest customers for the year ended December 31, 2018 were Anadarko Petroleum Corporation 22.3%, Shell Oil Company 13.1%, and ExxonMobil Oil Corporation 12.5%. Our largest customers for the years ended December 31, 2017 and 2016, respectively, were Anadarko Petroleum Corporation 24.0% and 16.8%, Shell Oil Company 15.5% and 15.9%, and BHP Billiton Ltd. 10.6% and 9.7%. Shell Oil Company is a marketing agent for numerous producers who are dedicated to us. The loss of any of these customers or a significant reduction in the crude oil volumes they have dedicated to us for handling would have a material adverse effect on our financial position, results of operations and cash flows.