GENESIS ENERGY LP
Form 10-K
February 27, 2015

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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, 2014
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 and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit 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 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, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	x	Accelerated filer	¨

Non-accelerated filer o Smaller reporting company ¨

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, 2014 (the last business day of Registrant's most recently completed second fiscal quarter) was approximately $3.9 billion based on $56.04 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 27, 2015, the Registrant had 94,989,221 Class A Common Units and 39,997 Class B Common Units outstanding.

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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 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 and other such references are forward-looking statements. 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," "position," "projection," "str "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, NaHS, 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;
- throughput levels and rates;

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- 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 energy 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 or other businesses for which we transport crude oil, petroleum or other products or to whom we sell such 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, accounting pronouncements, and safety, environmental and employment laws and regulations;
- the effects of production declines resulting from the suspension of drilling in the Gulf of Mexico and the effects of future laws and government regulation resulting from the Macondo accident and oil spill in the Gulf;
- planned capital expenditures and availability of capital resources to fund capital expenditures;
- our inability to borrow or otherwise access funds needed for operations, expansions or capital expenditures as a result of our credit agreement and the indenture governing our notes, which contain various affirmative and negative covenants;
- loss of key personnel;
- 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;
- 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.

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PART I

Item 1. Business

General

We are a growth-oriented master limited partnership formed in Delaware in 1996 and focused on the midstream segment of the oil and gas industry in the Gulf Coast region of the United States, primarily Texas, Louisiana, Arkansas, Mississippi, Alabama, Florida, Wyoming and in the Gulf of Mexico. Our common units are traded on the New York Stock Exchange under the ticker symbol “GEL.” Our principal executive offices are located at 919 Milam, Suite 2100, Houston, Texas 77002 and our telephone number is (713) 860-2500. Except to the extent otherwise provided, the information contained in this annual report is as of December 31, 2014.

We provide an integrated suite of services to oil producers, refineries, and industrial and commercial enterprises. Our business activities are primarily focused on providing services around and within refinery complexes. Upstream of the refineries, we provide gathering and transportation of crude oil. Within the refineries, we provide services to assist in their sulfur balancing requirements. Downstream of refineries, we provide transportation services as well as market outlets for their finished refined products. 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 trucks. Substantially all of our revenues are derived from providing services to integrated oil companies, large independent oil and gas or refinery companies, and large industrial and commercial enterprises.

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.

In the fourth quarter of 2014, we reorganized our operating segments as a result of a change in the way our Chief Executive Officer, who is our chief operating decision maker, evaluates the performance of operations, develops strategy and
allocates resources. The results of our marine transportation activities, formerly reported in the Supply and Logistics Segment, are now reported in our Marine Transportation Segment. In addition, the results of our offshore and onshore pipeline transportation activities, formerly reported in the Pipeline Transportation Segment, are now reported separately in our Onshore Pipeline Transportation Segment and Offshore Pipeline Transportation Segment.

As a result of the above changes, we currently manage our businesses through five divisions that constitute our reportable segments – Onshore Pipeline Transportation, Offshore Pipeline Transportation, Refinery Services, Marine Transportation and Supply and Logistics. Our disclosures related to prior periods have been recast to reflect our reorganized segments.

Onshore Pipeline Transportation Segment

Crude Oil Pipelines

We own four onshore crude oil pipeline systems, with approximately 500 miles of pipe located primarily in Alabama, Florida, Louisiana, Mississippi and Texas. The Federal Energy Regulatory Commission, or FERC, regulates the rates charged by three 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.

CO_2 Pipelines

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 a large, independent 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.

Offshore Pipeline Transportation Segment

We own interests in various offshore crude oil pipeline systems, with approximately 1,200 miles of pipe and an aggregate design capacity of approximately 1,200 MBbls per day, located offshore in the Gulf of Mexico, a producing region representing approximately 15% of the crude oil production in the United States in 2014. For example, we own a 28% interest in the Poseidon pipeline system and a 50% interest in 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 a 50%

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interest in Southeast Keathley Canyon Pipeline Company, LLC, or SEKCO, which is a deepwater pipeline servicing the Lucius field in the southern Keathley Canyon area of the Gulf of Mexico that became operational in 2014. Our offshore pipelines generate cash flows from fees charged to customers or substantially similar arrangements that otherwise limits our direct exposure to changes in commodity prices.

Each of our offshore pipelines currently has significant available capacity to accommodate future growth in the fields from which the production is dedicated to that pipeline as well as to transport volumes from non-dedicated fields both currently in production and to be developed in the future.

Refinery Services Segment

We primarily (i) provide services to ten refining operations located primarily in Texas, Louisiana, Arkansas, Oklahoma and Utah; (ii) operate significant storage and transportation assets in relation to those services; and (iii) sell NaHS and caustic soda to large industrial and commercial companies. Our refinery services primarily involve processing refiners' high sulfur (or "sour") gas streams to remove the sulfur. Our refinery services footprint also includes terminals, and we utilize railcars, ships, barges and trucks to transport product. Our refinery services contracts are typically long-term in nature and have an average remaining term of three years. NaHS is a by-product derived from our refinery 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 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 marketers of NaHS in North and South America.

Marine Transportation Segment

We own a fleet of 71 barges (62 inland and 9 offshore) with a combined transportation capacity of 2.6 million barrels and 33 push/tow boats (24 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.

In November 2014 we also acquired from Mid Ocean Tanker Company, LLC, 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. Most of 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. All of our vessels operate under the United States flag and are qualified for domestic trade under the Jones Act.

Supply and Logistic Segment

Our supply and logistics segment is focused on utilizing our knowledge of the crude oil and petroleum markets to provide oil and gas producers, refineries and other customers with a full suite of services. Our supply and logistics segment
owns or leases trucks, terminals, gathering pipelines, railcars, and rail loading and 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. We have access to a suite of more than 300 trucks, 400 trailers, 562 railcars, and terminals and tankage with 2.9 million barrels of storage capacity in multiple locations along the Gulf Coast as well as capacity associated with our three common carrier crude oil pipelines. Our crude-by-rail operations consist of a total of six facilities, either in operation or under construction, designed to load and/or unload crude oil. The two facilities located in Texas and Wyoming were designed primarily to load crude oil produced locally onto railcars for further transportation to refining markets. The four other facilities (two in Louisiana, one in Mississippi and one in Florida) were designed primarily to unload crude oil from railcars into pipelines, or onto barges, for delivery to refinery customers. Usually, our supply and logistics segment experiences limited 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.

Our Objectives and Strategies

Our primary business objectives are to generate stable cash flows that allow us to make quarterly cash distributions to our unitholders and to increase those distributions over time. We plan to achieve those objectives by executing the following business and financial strategies.

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Business Strategy

Our primary business strategy is to provide an integrated suite of services to oil and gas producers, refineries and other customers. Successfully executing this strategy should enable us to generate and grow sustainable cash flows. 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 refinery services, onshore and offshore pipeline systems, marine transportation and supply and logistics businesses;
- Economically expanding our pipeline and terminal operations;
- 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.

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 commodity price risks;
- Maintain a sound, disciplined capital structure; 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:

- We have limited commodity price risk exposure. 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 exposure to movements in the price of the commodity, although we cannot completely eliminate commodity price exposure. Our risk management policy requires that we monitor the effectiveness of the hedges to maintain a value at risk of such hedged inventory that does not exceed $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 businesses encompass a balanced, diversified portfolio of customers, operations and assets. We operate five business segments and own and operate assets that enable us to provide a number of services to oil producers, refinery owners, and industrial and commercial enterprises that use 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 providing services around and within refinery complexes. We are not dependent upon any one customer or principal location for our revenues.
- Our onshore and offshore pipeline transportation and related assets are strategically located. Our pipelines are critical to the ongoing operations of our producer and refiner customers. In addition, a majority of our terminals are located in areas that can be accessed by truck, rail or barge.
- We believe we are one of the largest marketers of NaHS in North and South America. We believe the scale of our well-established refinery services operations as well as our integrated suite of assets provides us with a unique cost advantage over some of our existing and potential competitors.
- Our supply and logistics business is 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.

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- 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. There are a limited number of Jones Act qualified vessels participating in United States coastwise trade. All of our vessels operate under the United States flag and are qualified for United States coastwise trade under the Jones Act.
- Our businesses provide consistent consolidated financial performance. Our consistent and improving financial performance, combined with our conservative capital structure, has allowed us to increase our distribution for thirty-eight consecutive quarters as of our most recent distribution declaration. During this period, thirty-three of those quarterly increases have been 10% or greater as compared to the same quarter in the preceding year.
- We are financially flexible and have significant liquidity. As of December 31, 2014, we had $438.8 million available under our $1 billion credit agreement, including up to $105.0 million available under the $150 million petroleum products inventory loan sublimit, and $89.2 million available for letters of credit. Our inventory borrowing base was $45.0 million at December 31, 2014.
- 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.
- 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, 2013. Additional information regarding most of these items may be found elsewhere in this report.

Acquisition of the M/T American Phoenix

On November 13, 2014, we completed the acquisition of the M/T American Phoenix from Mid Ocean Tanker Company for $157 million, which became part of our offshore marine transportation business. The M/T American Phoenix is a modern double-hulled, Jones Act qualified tanker with 330,000 barrels of cargo capacity that was placed into service during 2012. That acquisition complements and further integrates our existing operations, including our inland barge business (comprised of 62 barges and 24 push/tow boats) and our offshore tank barge and tug business (comprised of 9 boats and 9 barges).

Inland Marine Barge Transportation Expansion

We ordered 12 new-build barges and 10 new-build push boats for our inland marine barge transportation fleet. We have accepted delivery of 8 of those barges and 2 of those push boats as of December 2014. We expect to take delivery of those remaining vessels periodically into 2016.

ExxonMobil Baton Rouge Project

We are improving existing assets and developing new infrastructure in Louisiana, including connecting to Exxon Mobil Corporation’s Baton Rouge refinery, one of the largest refinery complexes in North America, with more than 500,000 barrels per day of refining capacity. Our investment includes improving our existing terminal at Port Hudson, Louisiana, and building a new crude oil unit train unload facility at Scenic Station as well as constructing a new 17-mile 24-inch diameter crude oil pipeline connecting Port Hudson to the Baton Rouge Scenic Station and continuing downstream to the Exxon Mobil Anchorage Tank Farm. The Port Hudson upgrades and new crude oil pipeline were completed in the first quarter of 2014, and Scenic Station became operational in July 2014.

Baton Rouge Terminal

We are constructing a new crude oil, intermediates and refined products import/export terminal in Baton Rouge that will be located near the Port of Greater Baton Rouge and will be pipeline-connected to the port's existing deepwater docks on the Mississippi River. We will initially construct approximately 1.1 million barrels of tankage for the storage of crude oil, intermediates and/or refined products with the capability to expand to provide additional terminaling services to our customers. In addition, we will construct a new pipeline from the terminal that will allow for deliveries to existing Exxon Mobil facilities in the area, as well as connect our previously constructed 17 mile line to the terminal allowing for receipts from the Scenic

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Station Rail Facility. Shippers to Scenic Station will have access to both the local Baton Rouge refining market, as well as the ability to access other attractive refining markets via our Baton Rouge Terminal. The Baton Rouge Terminal is expected to be operational by the end of the third quarter of 2015.

Deepwater Gulf of Mexico Pipeline Joint Venture

In June 2014, Southeast Keathley Canyon Pipeline Company LLC, or SEKCO, our 50/50 joint venture with Enterprise Products Partners, L.P., completed its deepwater pipeline serving the Lucius oil and gas field in the southern Keathley Canyon area of the Gulf of Mexico. SEKCO has crude oil transportation agreements with six Gulf of Mexico producers, including Anadarko U.S. Offshore Corporation, Apache Deepwater Development LLC, Exxon Mobil Corporation, Eni Petroleum US LLC, Petrobras America and Plains Offshore Operations, Inc. Those producers have dedicated their production from Lucius to the 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. Enterprise Products served as construction manager and is the operator of the SEKCO pipeline. SEKCO's customers commenced paying fees to SEKCO upon completion of its pipeline and commenced crude oil deliveries to the SEKCO pipeline in the first quarter of 2015.

The 149-mile, 18-inch diameter pipeline, designed to have a 115,000 barrel per day capacity, connects the Lucius-truss spar floating production platform to an existing junction platform at South Marsh Island that is part of the Poseidon pipeline system, in which we own a 28% interest. See additional discussion regarding this project in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources."

Rail Projects

Walnut Hill - In 2013, we completed construction on the second phase of our crude-by-rail unloading terminal at Walnut Hill, Florida, which includes a 100,000 barrel storage tank, related equipment and connections to our Jay System. In April 2014, we completed construction of an additional 110,000 barrel storage tank at our Walnut Hill, Florida crude-by-rail terminal, which will allow us to handle increased rail and pipeline demand. That terminal is connected to our Jay System and now includes 210,000 Barrels of capacity.

Wink - In April 2014, we completed construction on the second phase of our crude oil rail loading facility in Wink, Texas, which allows us to more efficiently load full unit trains. That facility was designed to move crude oil from West Texas to other markets and gives us the capability to load Genesis and third party railcars.

Natchez - During the first quarter of 2014, we completed construction on the second phase of our crude oil rail unloading/loading facility at our existing terminal located in Natchez, Mississippi, which provides an additional 60 railcar spots and additional heated tanks. That facility is designed to facilitate the movement of Canadian bitumen/dilbit to Gulf Coast markets via the Mississippi River. This facility has the capability to heat and unload bitumen/dilbit, load trucks, blend crude oil and load barges for distribution to refineries.

Raceland - The Raceland Rail Facility, a new crude oil unit train unloading facility capable of unloading up to two unit trains per day, which is located in Raceland, Louisiana, and will be connected to existing midstream infrastructure that will provide direct pipeline access to the Louisiana refining markets and is expected to be operational in the second half of 2015.

Thirty-eight Consecutive Distribution Rate Increases

We have increased our quarterly distribution rate for thirty-eight consecutive quarters. Thirty-three of those quarterly increases have been 10% or greater as compared to the same quarter in the preceding year. On February 13, 2015, we paid a quarterly cash distribution of $0.595 (or $2.38 on an annualized basis) per unit to unitholders of record as of February 2, 2015, an increase of 2.6% from the distribution in the prior quarter, and an increase of 11.2% from the distribution in February 2014. As in the past, future increases (if any) in our quarterly distribution rate will depend on our ability to execute critical components of our business strategy.

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Organizational Structure
The following chart depicts our organizational structure at December 31, 2014.
Description of Segments and Related Assets
We conduct our business through five primary segments: Onshore Pipeline Transportation, Offshore Pipeline Transportation, Refinery Services, Marine Transportation and Supply and Logistics. 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 12 to our Consolidated Financial Statements in Item 8.
Onshore Pipeline Transportation
Crude Oil Pipelines
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 (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.

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	Texas System	Jay System	Mississippi System	Louisiana System
Product	Crude Oil	Crude Oil	Crude Oil	Crude Oil
Interest Owned	100%	100%	100%	100%
Design Capacity (Bbls/day)	Existing 8" - 60,000 Looped 18" - 275,000	150,000	45,000	350,000
2014 Throughput (Bbls/day) (1)	58,829	24,131	14,829	18,436
System Miles	109	135	235	17
Approximate owned tankage storage capacity (Bbls)	220,000	230,000	247,500	350,000
Location	West Columbia, TX to Webster, TX Webster, TX to Texas City, TX Webster, TX to Houston, TX	Southern AL/FL to Mobile, AL	Soso, MS to Liberty, MS	Port Hudson, LA to Baton Rouge, LA Baton Rouge, LA to Port Allen, LA
Rate Regulated	TXRRC	FERC	FERC	FERC

(1) Our Louisiana pipeline system only had throughput for partial year during 2014, as it was placed into service in March 2014.

- Texas System. Our Texas System transports crude oil from West Columbia to several delivery points near Houston, Texas. 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 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 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 the Baton Rouge Scenic Station 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. This pipeline system was completed in the first quarter of 2014 and Scenic Station became fully operational in July 2014.

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CO_2 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 oil fields in eastern Mississippi. We have a transportation services agreement through 2028 related to the transportation of CO_2 on our Free State pipeline.

Denbury Resources, Inc., or Denbury, has leased the NEJD System from us through 2028. Our NEJD System transports CO_2 to tertiary oil recovery operations in southwest Mississippi.

Customers

Our customers on our Mississippi, Jay, Louisiana, and Texas systems are primarily large, energy companies. Denbury has exclusive use of the NEJD Pipeline System and 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. Currently, Denbury also has rights to exclusive use of our Free State pipeline.

Revenues from customers of our onshore pipeline transportation segment did not account for more than ten percent of our consolidated revenues. We do not believe the loss of any single customer would have a material adverse effect on us.

Competition

Competition among common carrier pipelines is based primarily on posted tariffs, quality of customer service and proximity to production, refineries 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. Additionally, Denbury is required to use our Free State pipeline for any transportation of CO_2 within a dedicated area.

Offshore Pipeline Transportation

Offshore Crude Oil Pipelines

We own interests in several crude oil pipelines and related infrastructure located offshore in the Gulf of Mexico, a producing region representing approximately 15% of the crude oil production in the United States in 2014. CHOPS is one of the largest crude oil pipelines (in terms of both length and design capacity) located in the Gulf of Mexico. The SEKCO Pipeline, our 50/50 joint venture with Enterprise Products that was declared complete in June 2014, serves the Lucius oil and gas field in the southern Keathley Canyon area of the Gulf of Mexico. The table below reflects our interests in our operating offshore crude oil pipelines.

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	CHOPS	Poseidon	SEKCO	Odyssey	Eugene Island
Product	Crude Oil	Crude Oil	Crude Oil	Crude Oil	Crude Oil
Interest Owned	50%	28%	50%	29%	23%
System Miles	380	367	149	120	184
Design Capacity (Bbls/day) (1)	500,000	350,000	115,000	200,000	39,000
2014 Throughput (Bbls/day)	183,726	209,647	N/A(2)	46,717	6,458
Location	Gulf of Mexico (primarily offshore of Texas and Louisiana)	Gulf of Mexico (primarily offshore of Louisiana)	Gulf of Mexico (primarily offshore of Louisiana)	Gulf of Mexico (primarily offshore of Louisiana)	Gulf of Mexico (primarily offshore of Louisiana)
Rate Regulated	No	No	No	No	FERC
In-Service Date	2004	1996	2014	1,998	1983

(1) Capacity figures represent gross system capacity except Eugene Island, which represents our net capacity in the undivided interest (34%) in that system. Ultimate capacities can vary primarily as a result of pressure requirements, installed pumps, related facilities and the viscosity of the oil actually moved.

(2) Crude throughput volumes on the SEKCO pipeline commenced in the first quarter of 2015. We began earning certain minimum fees upon completion of the SEKCO pipeline in 2014.

- 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. Enterprise Products owns the remaining 50% interest in, and operates, the joint venture.
- 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. Affiliates of Enterprise Products and Shell each own a 36% interest in Poseidon. An affiliate of Enterprise Products serves as the operator.
- SEKCO Pipeline. SEKCO, our 50/50 joint venture with Enterprise Products, is a deepwater pipeline serving the Lucius oil and gas field located in the southern Keathley Canyon area of the Gulf of Mexico. That pipeline was completed in June 2014. SEKCO has crude oil transportation agreements with six Gulf of Mexico producers, including Anadarko U.S. Offshore Corporation, Apache Deepwater Development LLC, Exxon Mobil Corporation, Eni Petroleum US LLC, Petrobras America and Plains Offshore Operations, Inc. Those producers have dedicated their production from Lucius to the 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. Enterprise Products served as construction manager and is the operator of the SEKCO pipeline. SEKCO's customers commenced paying fees to SEKCO upon completion of its pipeline and commenced crude oil deliveries to the SEKCO pipeline in the first quarter of 2015.
- 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, and an affiliate of Shell serves as the operator.
- 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, Chevron-Texaco, ConocoPhillips and Shell Oil Company. An affiliate of Shell serves as the operator.

Customers

Due to the cost of finding, developing and producing oil properties in the deepwater regions of the Gulf of Mexico, most of our offshore pipeline customers are integrated oil companies and other large producers, and those producers desire to have longer-term arrangements ensuring that their production can access the markets.

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Usually, our offshore 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. We do not believe the loss of any single customer would have a material adverse effect on us.

Competition

The principal competition for our offshore pipelines includes other crude oil 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, 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.

Refinery Services

Our refinery services segment (i) provides sulfur-extraction services to ten refining operations primarily located in Texas, Louisiana, Arkansas, Oklahoma and Utah, (ii) operates significant storage and transportation assets in relation to our business and (iii) sells NaHS and caustic soda (or NaOH) to large industrial and commercial companies. Our refinery services activities involve processing 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 refinery services activities. A majority of the NaHS we receive is sourced from refineries owned and operated by large companies, including Phillips 66, CITGO, HollyFrontier, and Ergon. Our ten refinery services contracts have an average remaining life of three years. The timing upon which these contracts renew vary based upon location and terms specified within each specific contract.

Our refinery services footprint includes terminals in the Gulf Coast, the Midwest, Montana, Utah, British Columbia and South America. In conjunction with our supply and logistics segment, we sell and deliver (via railcars, ships, barges and trucks) NaHS and caustic soda to over 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 services utilizing NaHS units at ten refining locations. Additionally, we have marketing arrangements at four third-party sites. Thus, even though some of our customers have elected to own the sulfur removal facilities located at their refineries, we operate those facilities. Those customer-owned NaHS facilities are located primarily in the southeastern United States.

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 United States, Canada and Mexico. We also export the NaHS to South America for sale to customers for mining in Peru and Chile. No customer of the refinery services segment is responsible for more than ten percent of our consolidated

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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. We do not believe the loss of any single customer would have a material adverse effect on us.

Competition

Our competitors for the supply of NaHS consist primarily of parties who produce NaHS as a by-product of processes involved with agricultural pesticide products, plastic additives and lubricant viscosity. Typically our competitors for the production of NaHS have only one manufacturing location and they do not have the logistical infrastructure that we have to supply customers. Our primary competitor has been AkzoNobel, a chemical manufacturing company that produces NaHS primarily in its pesticide operations.

Our competitors for sales of caustic soda include manufacturers of caustic soda. These competitors supply caustic soda to our refinery services operations and support us in our third-party NaOH 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 NaOH from one source.

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

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 United States, 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 customers along the Gulf Coast. The below table includes operational information relating to our marine transportation fleet:

	Inland	Offshore	American Phoenix
Total Design Capacity (Bbls) (in thousands)	1,718	884	330
Capacity Range (Bbls) (in thousands) [1]	23-39	65-136	330
Number of:			
Push/Tug Boats	24	9	—
Barges	62	9	—
Product Tankers	—	—	1

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

Customers

Our marine customers are primarily large energy companies and refiners. The M/T American Phoenix is currently operating under long term charters into 2020 with high quality counterparties, including major energy companies. 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. 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 under spot contracts. Most have been our customers for many years and we 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

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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 90% of the marine transportation's revenues under term contracts during 2014, 2013 and 2012. 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 2014, 2013 and 2012, approximately 80%, 67% and 37%, respectively, of marine transportation's revenues were from term contracts and 20%, 33% and 63%, respectively, from spot contracts.

Revenues from customers of our marine transportation segment did not account for more than ten percent of our consolidated revenues. We do not believe the loss of any single customer would have a material adverse effect on us.

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.

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.

Supply and Logistics

We provide supply and logistics services to Gulf Coast oil and gas producers and refineries 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 portfolio of logistical assets consisting of trucks, terminals, pipelines, railcars and barges. 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 and marketing crude oil to refiners. Not unlike our crude oil operations, we also gather refined products from refineries, transport refined products via truck, railcar and barge, and sell refined products to customers in wholesale markets. For these services, we generate fee-based income and 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 oil and products, minus the associated costs of aggregation and transportation.

Our crude oil supply and logistics operations are concentrated in Texas, Louisiana, Alabama, Florida, Mississippi and Wyoming. These operations help to ensure (among other things) a base supply source for our oil pipeline systems and our refinery customers while providing our producer customers with a market outlet for their production. We attempt to limit our commodity price risk in our supply and logistics 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 gathering lines, trucks, railcars, barges, terminals and pipelines, we are able to provide transportation related services to, and back-to-back gathering and marketing arrangements with, crude oil producers and refiners. 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 transport approximately 80,000 barrels per day of crude oil, much of which is produced from large and growing resource basins throughout Texas and the Gulf Coast. Given our network of terminals, we also have the ability to store crude oil during periods of contango (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 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.

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Our refined products supply and logistics operations are concentrated in the Gulf Coast region, principally Texas and Louisiana, and in Wyoming. Through our footprint of owned and leased 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.

We own five active crude oil rail loading/unloading facilities located in Baton Rouge, Louisiana; Walnut Hill, Florida; Wink, Texas; Natchez, Mississippi and Douglas, Wyoming which provide synergies to our existing asset footprint. We generally earn a fee for loading or unloading railcars at these facilities.

As discussed in "Recent Development and Growth Initiatives" above, in early 2013, we began construction on a new crude oil unit train unload facility at Scenic Station, connected to Exxon Mobil Corporation's Baton Rouge refinery. This facility became fully operational in July 2014.

Also, as discussed in "Recent Developments and Growth Initiatives" above, in the fourth quarter of 2013, we began construction on a new crude oil unit train unloading facility in Raceland, Louisiana which will connect to existing midstream infrastructure that will provide direct pipeline access to refineries from the Baton Rouge area to the Gulf of Mexico. This facility is expected to be operational in the second half of 2015.

Our industrial gases supply and logistics operations supply CO_2 to industrial customers under four long-term contracts. We obtain our CO_2 supply pursuant to our volumetric production payments (also known as VPPs). Our existing customer contracts expire between 2015 and 2023.

Within our supply and logistics business segment, we employ many types of logistically flexible assets. These assets include 300 trucks, 400 trailers, 562 railcars, and terminals and other tankage with 2.9 million barrels of leased and owned storage capacity in multiple locations along the Gulf Coast, accessible by pipeline, truck, rail or barge. Our leased railcars consist of approximately 94 refined product railcars and 468 crude oil railcars.

Customers

Our supply and logistics business encompasses hundreds of producers and numerous refineries, for which we provide transportation related services, as well as gather from and market to crude oil and refined products. During 2014, more than 10% of our consolidated revenues were generated from Shell, however, we do not believe that the loss of any one supply and logistics customer would have a material adverse effect on us as these products are readily marketable commodities.

Competition

In our crude oil supply and logistics 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. In our refined products supply and logistics operations, we compete primarily with regional companies. Competitive factors in our supply and logistics 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.

Geographic Segments

All of our operations are in the United States. Additionally, we transport and sell NaHS to customers in South America and Canada. Revenues from customers in foreign countries totaled approximately $18 million, $17.0 million and $19.3 million in 2014, 2013 and 2012, respectively. The remainder of our revenues was generated from sales to customers in the United States.

Credit Exposure

Due to the nature of our operations, a disproportionate percentage of our trade receivables constitute obligations of oil companies, independent refiners, and mining and other industrial companies that purchase NaHS. 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 customer base. Our portfolio of accounts receivable is comprised in large part of the obligations of large integrated and downstream energy companies with 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.

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When we market crude oil and petroleum products and NaHS, 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 pipeline transportation segment.

Employees

To carry out our business activities, we employed approximately 1,200 employees at December 31, 2014. None of our employees are represented by labor unions, and 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, and Louisiana 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.

Our offshore pipelines 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. In addition to our established tariffs, a portion of the volume on our Texas System is now shipped under joint tariffs with Enterprise Products and Exxon. 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 United States Coast Guard (“USCG”), the Environmental Protection Agency (EPA), the Department of Homeland Security (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 by 2015.

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 ("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.

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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.

We believe that additional security and environmental related regulations may be imposed on the marine industry in the form of contingency planning requirements. Generally, we endorse the anticipated additional regulations and believe we are currently operating to standards at least equal to anticipated additional regulations.

Jones Act: The Jones Act is a federal law that restricts maritime transportation between locations in the United States to vessels built and registered in the United States and owned and manned by United States 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 United States-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 United States-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 United States of a national emergency or a threat to the national security, the United States Secretary of Transportation may requisition or purchase any vessel or other watercraft owned by United States citizens (including us, provided that we are considered a United States citizen for this purpose). If one of our tow boats or barges were purchased or requisitioned by the United States 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 ("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 and Health Administration ("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.

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 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

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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 oil and gas exploration and production wastes as "hazardous wastes." 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

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 oil, into navigable waters of the United States, as well as state waters. Permits must be obtained to discharge pollutants into these waters. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. 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, or the OPA, is the primary federal law for oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. Under the OPA, strict, joint and several liability may be imposed on "responsible parties" 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 and natural resource damages, resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A “responsible party” includes the owner or operator of an onshore facility.

Noncompliance with the Clean Water Act or the OPA may result in substantial civil and criminal penalties. We believe we are in material compliance with each of these requirements.

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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.
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.
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 January 2011. The EPA adopted the stationary source rule, also known as the "Tailoring Rule," in May 2010, and it also became effective 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 December 19, 2014, EPA issued two memoranda providing initial guidance on GHG permitting requirements in response to the Court’s decision in UARG v. EPA. In its preliminary guidance, EPA indicates it will undertake a rulemaking action no later than December 31, 2015, to rescind any PSD permits issued under the portions of the Tailoring Rule that were vacated by the Court. In the interim, EPA issued a narrowly crafted “no action assurance” indicating it will exercise its enforcement discretion not to pursue enforcement of the terms and conditions relating to GHGs in an EPA-issued PSD permit, and for related terms and conditions in a Title V permit. 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 oil and natural gas production and onshore processing, transmission, storage and distribution facilities, which may include certain or our facilities, beginning in 2012 for emissions occurring in 2011. As a result of this continued regulatory focus, future GHG regulations of the oil and natural gas industry remain a possibility.
Further, the U.S. Congress has considered various proposals to reduce GHG emissions that may impose a carbon emissions tax, a cap-and-trade program or other programs aimed at carbon reduction, 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 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. 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.

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 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 195. These regulations, among other things, address pipeline integrity management and pipeline

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operator qualification rules. 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 DOT 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. Due to the proximity of all of our pipelines to water crossings and populated areas, we have designated all of our pipelines as affecting HCAs. 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.

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 refinery 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.

States are responsible for enforcing the federal regulations and more stringent state pipeline regulations and inspection with respect to 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 United States 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.

Available Information

The public may read and copy any materials that we file with the SEC at the SEC’s Public Reference Room at 100 F Street, N.E., Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. 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.

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Item 1A. Risk Factors
Risks Related to Our Business
We may not be able to fully execute our growth strategy if we are unable to raise debt and equity capital at an affordable price.
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, ultimately, increase distributions to unitholders.
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.
The capital and credit markets have previously been, and may in the future be, disrupted and volatile as a result of adverse conditions. The government response to the disruptions in the financial markets may not adequately restore investor or customer confidence, stabilize such markets, or increase liquidity and the availability of credit to businesses. If the credit markets experience volatility and the availability of funds are limited, we may experience difficulties in accessing capital for significant growth projects or acquisitions which could adversely affect our strategic plans.
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.
Fluctuations in interest rates could adversely affect our business.
We have exposure to movements in interest rates. The interest rates on our credit facility ($550.4 million outstanding at December 31, 2014) 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, refined products, and caustic soda;
- the volumes of sodium hydrosulfide, or NaHS, that we receive for our refinery services and the prices at which we sell NaHS;
- the demand for our services;
- the level of competition;
- 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;

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- 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 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, 2014, we had approximately $550.4 million outstanding of senior secured indebtedness and an additional $1,050.6 million of senior unsecured indebtedness.

We must comply with various affirmative and negative covenants contained in our credit facilities. Among other things, these covenants limit our ability to:

- incur additional indebtedness or liens;
- 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; or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flow 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 facilities, 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 facility or under arrangements that may have terms and conditions at least as restrictive as those contained in our existing credit facility. 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 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.

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Our profitability and cash flow are dependent on our ability to increase or, at a minimum, maintain our current commodity—oil, refined products, 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 — oil, refined products, NaHS and caustic soda — volumes. We access commodity volumes through two sources, producers and service providers (including gatherers, shippers, marketers and other aggregators). 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 transportation operations) or we can purchase the commodity from our customer and resell it to another party.

Our source of volumes depends on successful exploration and development of additional oil reserves by others; continued demand for our refinery 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 oil and refined products available to us 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. Thus, oil production in our market area may not rise to sufficient levels to allow us to maintain or increase the commodity volumes we have historically realized.

Our ability to access NaHS depends primarily on the demand for our proprietary refinery services 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 refinery services 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 refinery services operations are dependent upon the supply of caustic soda and the demand for NaHS, as well as the operations of the refiners for whom we process sour gas.

Caustic soda is a major component of the proprietary sour gas 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 refinery services 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 sour gas treatment 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. The refineries’ need for our sour gas services is also 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.

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

Any decrease in this demand for crude oil by those refineries or connecting carriers to which 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.

We face intense competition to obtain oil and refined products volumes.

Our competitors — gatherers, transporters, marketers, brokers and other aggregators — include independents and major integrated energy companies, as well as their marketing affiliates, who vary widely in size, financial resources and

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experience. Some of these competitors have capital resources many times greater than ours and control substantially greater supplies of crude oil and other 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 producers or refiners to gather, refine, market, transport, store or otherwise handle any of these crude oil reserves, NaHS, caustic soda or other refined products. We compete with others for any such volumes on the basis of many factors, including:

- geographic proximity to the production;
- costs of connection;
- available capacity;
- rates;
- logistical efficiency in all of our operations;
- operational efficiency in our refinery services 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 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 and trucks can result in less demand for our transportation services.

Many of our customers' drilling activity levels and spending for transportation have been, and may continue to be, impacted by the current 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. During the last half of 2014, there was a significant decline in the price of crude oil and natural gas. Adverse price changes put downward pressure on drilling budgets for crude oil and gas producers, which could result in lower volumes than we otherwise would have seen being transported on our pipeline and transportation systems.

Non-utilization of certain assets, such as our leased railcars, 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 rail fleet for any period of time, we will still be obligated to pay the applicable fixed lease rate for such railcars. In addition, during the period of time that we are not utilizing such railcars, we will incur incremental costs associated with the cost of storing such railcars, and we will continue to incur costs for maintenance and upkeep. Our failure to utilize a significant portion of our leased railcars 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 or rail or transported by our pipelines. As a result, we may experience declines in our margin and profitability if our volumes decrease.

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Fluctuations in commodity prices could adversely affect our business.
Oil, natural gas, other petroleum products, NaHS and caustic soda prices are volatile and could have an adverse effect on our profits and cash flow. Prices for commodities can fluctuate in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. Price reductions in those commodities can cause material long and short term reductions in the level of production, throughput, volumes and, in some cases, margins. We attempt to limit commodity price risk exposure through back-to-back sales and hedges; however, we cannot completely eliminate commodity price risk exposure.
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 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 and caustic soda to customers in a variety of industries. Many 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 volatility of commodity prices, such as crude oil, 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. We have seen decreases in the prices of crude oil and natural gas in recent quarters and it is uncertain if the declines will continue in the future.
Our refinery services division is dependent on contracts with less than fifteen refineries and much of its revenue is attributable to a few refineries.
If one or more of our refinery customers that, individually or in the aggregate, generate a material portion of our refinery services revenue experience financial difficulties or changes in their strategy for sulfur removal such that they do not need our services, our cash flows could be adversely affected. For example, in 2014, approximately 60% of our refinery services' division NaHS by-product volumes was attributable to Phillips 66's refinery located in Westlake, Louisiana. That contract requires Phillips 66 to make available minimum volumes of sour gas to us (except during periods of force majeure). Although the primary term of that contract extends until 2018, if, for any reason, Phillips 66 does not meet its obligations under that contract for an extended period of time, such non-performance could have a material adverse effect on our profitability and cash flow.
We may not be able to renew our marine transportation time charters and contracts when they expire at favorable rates or at all.
During the year ended December 31, 2014, our marine transportation segment received approximately 80% of its revenue from time charters and other fixed contracts. However, there can be no assurance that any of these charters or contracts will be renewed.
If our exposure to the spot market increases, our marine transportation revenues could suffer and our expenses could increase.
During the year ended December 31, 2014, we earned approximately 20% of our marine transportation revenues from spot contracts, where rates are typically volatile and subject to short-term market fluctuations. The spot market for marine transportation services is highly competitive. 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
Our operations are subject to federal and state 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 increasingly stringent environmental protection and safety laws and regulations that

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restrict our operations, impose consequences of varying degrees for noncompliance, and require us to expend resources in an effort to maintain compliance. Moreover, our operations, including the transportation and storage of crude oil and other commodities, involves a risk that crude oil 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.

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

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other 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 has adopted two sets of related rules, one 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 January 2011. The EPA adopted the stationary source rule, also known as the "Tailoring Rule," in May 2010, and it also 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 December 19, 2014, EPA issued two memoranda providing initial guidance on GHG permitting requirements in response to the Court’s decision in UARG v. EPA. In its preliminary guidance, EPA indicates it will undertake a rulemaking action no later than December 31, 2015, to rescind any PSD permits issued under the portions of the Tailoring Rule that were vacated by the Court. In the interim, EPA issued a narrowly crafted “no action assurance” indicating it will exercise its enforcement discretion not to pursue enforcement of the terms and conditions relating to GHGs in an EPA-issued PSD permit, and for related terms and conditions in a Title V permit. 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 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. As a result of this continued regulatory focus, future GHG regulations of the oil and natural gas industry remain a possibility.

Further, the U.S. Congress has considered various proposals to reduce GHG emissions that may impose a carbon emissions tax, a cap-and-trade program or other programs aimed at carbon reduction, and almost half of the states, either individually or through multi-state regional initiatives, have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or GHG gas cap-and-trade programs. The net effect of this legislation is to impose increasing costs on the combustion of carbon-based fuels such as 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. 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.

The effect on our operations of CAA regulations, 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.

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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.

Our growth strategy may adversely affect our results of operations if we do not successfully integrate the businesses that we acquire or if we substantially increase our indebtedness and contingent liabilities to make acquisitions.

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.

If consummated, any acquisition or investment also likely would result in the incurrence of indebtedness and contingent liabilities and an increase in interest expense and depreciation and amortization expenses. A substantial increase in our indebtedness and contingent liabilities could have a material adverse effect on our business, as discussed above.

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 energy 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.

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.

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 United States 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.

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.

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.

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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 United States only to vessels operating under the U.S. flag, built in the United States, 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 oil and gas industry in response to the Deepwater Horizon drilling rig incident in the U.S. Gulf of Mexico and subsequent 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 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 United States coastwise trade and significantly increase competition with our fleet, which could have an adverse effect on our business. Events within the oil and 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 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 oil and gas industry, including us, to additional regulatory scrutiny and result in additional regulations and restrictions adversely affecting the U.S. oil and 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 United States and manned by U.S. crews. This has made it less expensive for certain areas of the United States 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 United States and transporting them on U.S. flag vessels, demand for our vessels and the charter rates for them could decrease.

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.

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

Maintenance of the United States 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 United States 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, 2014, we have a number of significant unitholders. For example, certain members of the Davison family (including their affiliates) and management owned approximately 17.1 million or 18% 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, 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 13.4% of our Class A Common Units and 76.9% 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;
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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, 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 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, other than CHOPS and are subject to the discretion of their respective management committees. Further, each joint venture's charter documents typically vest in its management committee sole discretion regarding 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.

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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 Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. A publicly-traded partnership can lose its status as a partnership for a number of reasons, including not having enough "qualifying income." If the Internal Revenue Service, or IRS, were to treat us as a corporation 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 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 every taxable year consists of "qualifying income." If less than 90% of our gross income for any taxable year is "qualifying income" from transportation or processing of natural resources including crude oil, natural gas or products thereof, interest, dividends or similar sources, 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, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes.

The decision of the United States Court of Appeals for the Fifth Circuit in Tidewater Inc. v. United States, 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.”

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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 35% 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 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 the cash available for distribution to our unitholders.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. Moreover, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact the value of an investment in 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 the cash available for distribution to our unitholders.

The tax treatment of publicly traded partnerships 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, may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation, affect or cause us to change our business activities, affect the tax considerations of an investment in us and change the character or treatment of portions of our income. From time to time, members of Congress propose and consider substantive changes to the existing U.S. federal income tax laws that would adversely affect the tax treatment of certain publicly traded partnerships. 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 flow.

A successful IRS contest of the federal income tax positions we take may adversely affect the market for our common units, and the cost of any IRS contest will reduce our cash available for distribution to our unitholders and our general partner.

We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. 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.

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.

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. 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 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. Prior distributions to unitholders in excess of the total net taxable income unitholders were allocated for a common unit, which decreased their tax basis in that common unit, will, in effect, become taxable income to unitholders if the common unit is sold at a price greater than their tax basis in that common unit, even if the

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price they receive is less than their 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 unitholders sell their units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

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

Investment in common units by tax-exempt entities, such as 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. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate and non-U.S. persons will be required to file 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.

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

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, 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 unitholders do not live in any of those jurisdictions. 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, 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 United States 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 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, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. If the IRS were to successfully challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss, and deduction among our unitholders.

A unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of those units. If so, 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.

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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 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.

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

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and unitholders receiving two Schedule K-1s) for one fiscal year. Our termination could also result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a common unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

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 19 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 19 to our Consolidated Financial Statements in Item 8.

Item 4. Mine Safety Disclosures

Not applicable.

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PART II

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

Our Class A common units are listed on the New York Stock Exchange (“NYSE”) under the symbol “GEL.” The following table sets forth, for the periods indicated, the high and low sale prices per common unit and the amount of cash distributions declared and paid per common unit.

	Price Range		Cash
	High	Low	Distributions (1)
2013			
1st Quarter	$49.34	$36.00	$ 0.4850
2nd Quarter	$54.91	$44.04	$ 0.4975
3rd Quarter	$55.99	$45.81	$ 0.5100
4th Quarter	$53.94	$48.00	$ 0.5225
2014			
1st Quarter	$56.80	$51.08	$ 0.5350
2nd Quarter	$57.47	$52.60	$ 0.5500
3rd Quarter	$56.32	$50.38	$ 0.5650
4th Quarter	$49.92	$34.57	$ 0.5800

(1) Cash distributions are shown in the quarter paid and are based on the prior quarter’s activities.

At February 27, 2015, we had 94,989,221 Class A common units outstanding. As of December 31, 2014, the closing price of our common units was $42.42 and we had approximately 47,500 record holders of our Class A common units, which include holders who own units through their brokers “in street name.”

Available cash consists generally of all of our cash receipts less cash disbursements, adjusted for net changes to cash reserves. Cash reserves are the amounts deemed necessary or appropriate, in the reasonable discretion of our general partner, to provide for the proper conduct of our business or to comply with applicable law, any of our debt instruments or other agreements. 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 11 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.

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Item 6. Selected Financial Data

The table below includes selected financial and other data for the Partnership for the years ended December 31, 2014, 2013, 2012, 2011 and 2010 (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."

	Year Ended December 31,				
	2014 (1)	2013 (1)	2012 (1)	2011 (1)	2010 (1)
Income Statement Data:					
Revenues:					
Pipeline transportation	86,453	86,508	76,290	62,190	55,652
Refinery services	207,401	205,985	196,017	201,711	151,060
Marine transportation	229,282	152,542	118,204	72,688	39,854
Supply and logistics	3,323,028	3,689,795	2,976,850	2,101,208	1,476,217
Total revenues	$3,846,164	$4,134,830	$3,367,361	$2,437,797	$1,722,783
Equity of earnings of equity investees	$43,135	$22,675	$14,345	$3,347	$2,355
Income (loss) from continuing operations after income taxes (2)	$106,202	$84,004	$97,337	$51,371	$(50,307)
Income (loss) from continuing operations after income taxes attributable to Genesis Energy, L.P. (2)	$106,202	$84,004	$97,337	$51,371	$(48,225)
Income from continuing operations after income taxes available to Common Unitholders	$106,202	$84,004	$97,337	$51,371	$20,163
Income (loss) from continuing operations attributable to Genesis Energy, L.P. per Common Unit: Basic and Diluted	$1.18	$1.00	$1.24	$0.76	$0.50
Cash distributions declared per Common Unit	$2.2300	$2.0150	$1.8225	$1.6500	$1.4900
Balance Sheet Data (at end of period):					
Current assets	$355,366	$535,223	$404,034	$376,104	$252,538
Total assets	$3,230,374	$2,862,202	$2,109,664	$1,730,844	$1,506,735
Long-term liabilities	$1,638,026	$1,317,912	$880,518	$688,778	$630,757
Total partners' capital	$1,229,203	$1,097,737	$916,495	$792,638	$669,264
Other Data:					
Volumes—continuing operations:					
Onshore crude oil pipeline (barrels per day)	116,225	104,026	92,897	82,712	67,931
Offshore crude oil pipeline (barrels per day) (3)	446,548	404,787	359,387	120,723	149,270
CO_2 pipeline (Mcf per day)	173,770	190,274	186,479	169,962	167,619
NaHS sales (DST)	150,038	147,297	142,712	147,670	145,213
NaOH sales (DST)	94,693	87,463	77,492	99,702	93,283
	99,139	99,651	79,174	56,903	49,992

Crude oil and petroleum products
sales (barrels per day)

(1) Our operating results and financial position have been affected by acquisitions. For additional information regarding our acquisitions and divestitures during 2014, 2013 and 2012, see Note 3 to our Consolidated Financial Statements included in Item 8.
(2) Includes executive compensation expense related to Series B and Class B awards borne entirely by our general partner in the amounts of $76.9 million for 2010.
(3) Includes barrels per day for CHOPS for the period we owned the pipeline in 2010.

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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 and focused on the midstream segment of the oil and gas industry primarily in the Gulf Coast region of the United States. We have a diverse portfolio of assets, including pipelines, refinery-related plants, storage tanks and terminals, railcars, rail loading and unloading facilities, trucks, barges and a product tanker. We provide an integrated suite of services to refineries, oil producers, and industrial and commercial enterprises that use NaHS and caustic soda. Our business activities are primarily focused on providing services around and within refinery complexes. We conduct our operations and own our operating assets through our subsidiaries and joint ventures.

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

- Overview of 2014 Results
- Segment Reporting Change
- 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 2014 Results

We reported income from continuing operations of $106 million, or $1.18 per common unit, in 2014 compared to income from continuing operations of $84 million, or $1.00 per common unit, in 2013.

Available Cash before Reserves increased $46.5 million in 2014 to $232.6 million as compared to 2013 Available Cash before Reserves of $186.1 million. See "Financial Measures" below for additional information on Available Cash before Reserves.

Segment Margin (as defined below in "Financial Measures") was $347.3 million in 2014, an increase of $67 million, or 24%, as compared to 2013. The increase in our Segment Margin primarily resulted from increases attributable to our offshore pipeline transportation, refinery services and marine transportation segments of $27 million, $9 million, and $39 million respectively. These increases, as discussed in more detail below, are primarily related to assets recently placed into service, including through acquisitions and organic growth projects. These increases were partially offset by decreases in Segment Margin attributable to our onshore pipeline transportation and supply and logistics segments of $3 million and $5 million respectively. These decreases are described in further detail below.

The above factors benefiting income from continuing operations were partially offset by an $18.1 million increase in interest expense attributable to additional long term debt outstanding and a $26.1 million increase in depreciation and amortization expense as a result of the effect of recently acquired and constructed assets placed in service.

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

Distribution Increase

In January 2015, we declared our thirty-eighth consecutive increase in our quarterly distribution to our common unitholders relative to the fourth quarter of 2014. Thirty-three of those quarterly increases have been 10% or greater as compared to the same quarter in the preceding year. In February 2015, we paid a distribution of $0.5950 per unit related to the fourth quarter of 2014, representing a 11.2% increase from our distribution of $0.5350 per unit related to the fourth quarter of 2013.

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Segment Reporting Change

In the fourth quarter of 2014, we reorganized our operating segments as a result of a change in the way our Chief Executive Officer, who is our chief operating decision maker, evaluates the performance of operations, develops strategy and
allocates resources. The results of our marine transportation activities, formerly reported in the Supply and Logistics Segment, are now reported in our Marine Transportation Segment. In addition, the results of our offshore and onshore pipeline transportation activities, formerly reported in the Pipeline Transportation Segment, are now reported separately in our Onshore Pipeline Transportation Segment and Offshore Pipeline Transportation Segments.

As a result of the above changes, we currently manage our businesses through five divisions that constitute our reportable segments – Onshore Pipeline Transportation, Offshore Pipeline Transportation, Refinery Services, Marine Transportation and Supply and Logistics. Our disclosures related to prior periods have been recast to reflect our reorganized
segments.

Acquisitions, Divestitures and Growth Initiatives

M/T American Phoenix

On November 13, 2014, we acquired the M/T American Phoenix from Mid Ocean Tanker Company for $157 million. The M/T American Phoenix is a modern double-hulled, Jones Act qualified tanker with 330,000 barrels of cargo capacity that was placed into service during 2012.

Inland Marine Barge Transportation Expansion

We ordered 12 new-build barges and 10 new-build push boats for our inland marine barge transportation fleet. We have accepted delivery of 8 of those barges and 2 of those push boats as of December 2014. We expect to take delivery of those remaining vessels periodically into 2016.

Acquisition of Additional Barges and Tug Boats

On August 28, 2013, we acquired substantially all of the assets of the downstream transportation business of Hornbeck Offshore Services, Inc. for approximately $230.9 million, which we refer to as our offshore marine transportation business and assets. The acquired business was primarily comprised of nine barges and nine tug boats that transport crude oil and refined petroleum products, principally serving refineries and storage terminals along the Gulf Coast, Eastern Seaboard, Great Lakes and Caribbean.

Divestiture of Fuel Procurement Business

On December 31, 2013 we sold our vehicle fuel procurement and delivery logistics management services business for $1 million. The operating results of that business, previously reported within our supply and logistics segment, was reclassified as discontinued operations in our Consolidated Statements of Operations for the years ended December 31, 2013 and 2012.

ExxonMobil Baton Rouge Project

We are improving existing assets and developing new infrastructure in Louisiana, including connecting to Exxon Mobil Corporation’s Baton Rouge refinery, one of the largest refinery complexes in North America, with more than 500,000 barrels per day of refining capacity. Our investment includes improving our existing terminal at Port Hudson, Louisiana, and building a new crude oil unit train unload facility at Scenic Station as well as constructing a new 17-mile 24-inch diameter crude oil pipeline connecting Port Hudson to the Baton Rouge Scenic Station and continuing downstream to the Exxon Mobil Anchorage Tank Farm. The Port Hudson upgrades and new crude oil pipeline were completed in the first quarter of 2014, and Scenic Station became operational in July 2014.

Baton Rouge Terminal

We are constructing a new crude oil, intermediates and refined products import/export terminal in Baton Rouge that will be located near the Port of Greater Baton Rouge and will be pipeline-connected to the port's existing deepwater docks on the Mississippi River. We will initially construct approximately 1.1 million barrels of tankage for the storage of crude oil, intermediates and/or refined products with the capability to expand to provide additional terminaling services to our customers. In addition, we will construct a new pipeline from the terminal that will allow for deliveries to existing Exxon Mobil facilities in the area, as well as connect our previously constructed 17-mile line to the terminal allowing for receipts from the Scenic Station Rail Facility. Shippers to Scenic Station will have access to both the local Baton Rouge refining market, as well as the ability to access other attractive refining markets via our Baton Rouge Terminal. The Baton Rouge Terminal is expected to be operational by the end of the third quarter of 2015.

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Deepwater Gulf of Mexico Pipeline Joint Venture

In June 2014, Southeast Keathley Canyon Pipeline Company LLC, or SEKCO, our 50/50 joint venture with Enterprise Products Partners, L.P., completed its deepwater pipeline serving the Lucius oil and gas field in the southern Keathley Canyon area of the Gulf of Mexico. SEKCO has crude oil transportation agreements with six Gulf of Mexico producers, including Anadarko U.S. Offshore Corporation, Apache Deepwater Development LLC, Exxon Mobil Corporation, Eni Petroleum US LLC, Petrobras America and Plains Offshore Operations, Inc. Those producers have dedicated their production from Lucius to the 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. Enterprise Products served as construction manager and is the operator of the new SEKCO pipeline. SEKCO's customers commenced paying fees to SEKCO upon completion of its pipeline and commenced crude oil deliveries to the SEKCO pipeline in the first quarter of 2015.

The 149-mile, 18-inch diameter pipeline, designed to have a 115,000 barrel per day capacity, connects the Lucius-truss spar floating production platform to an existing junction platform at South Marsh Island that is part of the Poseidon pipeline system, in which we own a 28% interest. See additional discussion regarding this project in Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources.”

Rail Projects

Walnut Hill - In 2013, we completed construction on the second phase of our crude-by-rail unloading terminal at Walnut Hill, Florida, which includes a 100,000 barrel storage tank, related equipment and connections to our Jay System. In April 2014, we completed construction of an additional 110,000 barrel storage tank at our Walnut Hill, Florida crude-by-rail terminal, which will allow us to handle increased rail and pipeline demand. That terminal is connected to our Jay System and now includes 210,000 Barrels of capacity.

Wink - In April 2014, we completed construction on the second phase of our crude oil rail loading facility in Wink, Texas, which allows us to more efficiently load full unit trains. That facility was designed to move crude oil from West Texas to other markets and gives us the capability to load Genesis and third party railcars.

Natchez - During the first quarter of 2014, we completed construction on the second phase of our crude oil rail unloading/loading facility at our existing terminal located in Natchez, Mississippi, which provides an additional 60 railcar spots and additional heated tanks. That facility is designed to facilitate the movement of Canadian bitumen/dilbit to Gulf Coast markets via the Mississippi River. This facility has the capability to heat and unload bitumen/dilbit, load trucks, blend crude oil and load barges for distribution to refineries.

Raceland - The Raceland Rail Facility, a new crude oil unit train unloading facility capable of unloading up to two unit trains per day, which is located in Raceland, Louisiana, and will be connected to existing midstream infrastructure that will provide direct pipeline access to the Louisiana refining markets and is expected to be operational in the second half of 2015.

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 and Income from Continuing Operations

Our revenues from continuing operations for the year ended December 31, 2014 decreased $288.7 million, or 7% from 2013. Additionally, our costs and expenses from continuing operations decreased $310.5 million or 8% between the two periods. The majority of our revenues and our costs are derived from the purchase and sale of crude oil and petroleum products. The significant decrease in our revenues and costs between 2014 and 2013 is primarily attributable to a decrease in market prices for crude oil and petroleum products as described below.

The average closing prices for West Texas Intermediate ("WTI") crude oil on the New York Mercantile Exchange ("NYMEX") decreased 5% to $93.00 per barrel in 2014, as compared to $97.97 per barrel in 2013.

Prices of crude oil and petroleum products have continued to decline since December 31, 2014. We would expect these changes in crude oil prices to continue to cause fluctuations in our revenues and similarly costs as derived from the purchase and sale of crude oil and petroleum products, therefore producing minimal impact on segment margin from these operations. We have focused the efforts of the our businesses, the majority of which are fee based, on customers further downstream in the energy value chain, where refiners are our primary customers rather than producers. The primary exception to this focus being the investments we have made in our offshore pipeline transportation assets, where we continue to believe that the development of long-lived deepwater reservoirs in the Gulf of Mexico will continue to be economically viable, in most cases, even in this lower commodity price environment. Given these facts, we would not expect changes in commodity prices

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to impact our Segment Margin in the same manner in which they impact our revenues and costs as derived from the purchase and sale of crude oil and petroleum products. See below for further discussion surrounding Segment Margin.
Income from continuing operations increased $22.2 million in 2014 from 2013. See "Overview of 2014 Results" above for additional discussion.
Revenues from continuing operations in 2013 increased $767.5 million, or 23% from 2012. Additionally, our costs and expenses from continuing operations increased $771.4 million, or 24%, between the two periods. The significant increase in our revenues and costs between 2013 and 2012 is primarily attributable to increased volumes from our continuing operations and our acquisitions, as well as slight increases in the market prices for crude oil and petroleum products. Volumes from continuing operations increased in our supply and logistics segment in 2013 by 26% from 2012, as explained in our supply and logistics Segment Margin discussion below. The average closing prices for WTI crude oil on the NYMEX were increased 4% to $97.97 per barrel in 2013, as compared to $94.21 per barrel in 2012.
Income from continuing operations decreased $13.3 million in 2013 to $84.0 million from $97.3 million in 2012. The decrease in income from continuing operations during 2013 was primarily due to the reversal in 2012 of a provision for uncertain tax positions combined with increases in interest expense, general and administrative expenses related to growth capital expenditures, and depreciation and amortization expense.
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,		
	2014	2013	2012
	(in thousands)		
Onshore pipeline transportation	$61,231	$64,349	$58,039
Offshore pipeline transportation	71,598	44,530	38,500
Refinery services	84,851	75,361	72,883
Marine transportation	86,239	47,726	37,528
Supply and logistics	43,345	48,394	55,383
Total Segment Margin	$347,264	$280,360	$262,333

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Year Ended December 31, 2014 Compared with Year Ended December 31, 2013

Onshore Pipeline Transportation Segment

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

	Year Ended December 31,	
	2014	2013
	(in thousands)	
Crude oil tariffs and revenues from direct financing leases—onshore crude oil pipelines	$42,347	$39,627
CO_2 tariffs and revenues from direct financing leases of CO_2 pipelines	25,241	26,342
Sales of onshore crude oil pipeline loss allowance volumes	9,049	11,526
Onshore pipeline operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	(21,868)	(19,217)
Payments received under direct financing leases not included in income	5,529	5,110
Other	933	961
Segment Margin	$61,231	$64,349
Volumetric Data (average barrels/day unless otherwise noted):		
Onshore crude oil pipelines:		
Texas	58,829	51,067
Jay	24,131	34,933
Mississippi	14,829	18,026
Louisiana (1)	18,436	—
Onshore crude oil pipelines total	116,225	104,026
CO_2 pipeline (average Mcf/day):		
Free State	173,770	190,274

(1) Represents volumes per day from the period the pipeline began operations in the first quarter of 2014.

Onshore Pipeline Transportation Segment Margin for 2014 decreased $3.1 million, or 5%, from 2013. The significant components of this change were as follows:

- Onshore crude oil pipeline loss allowance volumes, collected and sold, decreased Segment Margin by $2.5 million. Due to the nature of our tariffs on the Louisiana system, we do not collect or sell pipeline loss allowance volumes on this system.
- With respect to our onshore crude oil pipelines, tariff revenues increased $2.7 million, or 7%, primarily due to a net increase in throughput volumes of 12,199 barrels per day, primarily from the addition of our Louisiana pipeline system and increases in volumes on our Texas pipeline system. Our Louisiana pipeline system is a new 17-mile 24-inch diameter crude oil pipeline connecting Port Hudson to the Baton Rouge Scenic Station and continuing downstream to the Anchorage Tank Farm. This system was placed into service during the first quarter of 2014. These increases were partially offset by volume variances on our other onshore pipeline systems. Due to a mix of tariff rates on our onshore pipelines, the impact on onshore crude oil tariffs and revenues from these volume variances largely offset each other.
- Onshore pipeline operating costs, excluding non-cash charges, increased $2.7 million due to pipeline integrity maintenance expenditures on our onshore pipelines, employee compensation and related benefit costs and general increases in operating costs inclusive of safety program costs.
- Volumes on our Free State CO_2 pipeline system decreased 16,504 Mcf per day, or 9%. We provide transportation services on our Free State CO_2 pipeline system through 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 specific thresholds. As a result of this "incentive" tariff, fluctuations in volumes above a certain base level on our Free State CO_2 pipeline system have a limited impact on Segment Margin.

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Offshore Pipeline Transportation Segment

Our offshore pipeline transportation segment is comprised of interests in five offshore pipeline systems and related assets, including four joint ventures which we account for under the equity method of accounting. One of our wholly-owned subsidiaries (GEL Offshore Pipeline, LLC, or "GOPL") owns our undivided interest in the Eugene Island pipeline system. Segment Margin for our Offshore Pipeline Transportation Segment as disclosed below primarily consists of distributions received based on our ownership percentage in each of our four offshore pipeline joint ventures. These distributions typically correlate with volumes transported, as rates per barrel do not materially fluctuate between periods.

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

	Year Ended December 31,	
	2014	2013
	(in thousands)	
Offshore Pipeline Transportation Segment Margin(1)	$71,598	$44,530
Volumetric Data (average barrels/day unless otherwise noted):		
Offshore crude oil pipelines:		
CHOPS (2)	183,726	143,854
Poseidon (2)	209,647	207,372
Odyssey (2)	46,717	44,978
GOPL	6,458	8,583
SEKCO (3)	—	—
Offshore crude oil pipelines total	446,548	404,787

(1) Offshore Pipeline Transportation segment margin includes approximately $71 million and $44 million of distributions received from our offshore pipeline joint ventures accounted for under the equity method of accounting in 2014 and 2013, respectively.

(2) Volumes for our equity method investees are presented on a 100% basis.

(3) Our SEKCO pipeline was completed in June of 2014. Under the terms of SEKCO's transportation arrangements, its shippers commenced making minimum monthly payments at that time, even though they did not commence throughput of crude until January 2015.

Offshore Pipeline Transportation Segment Margin for 2014 increased $27 million, or 61%, from 2013. This increase is primarily attributable to the SEKCO pipeline, our 50/50 joint venture with Enterprise Products, being completed and earning certain minimum fees despite no crude throughput to date through 2014. This increase in segment margin from offshore crude oil pipelines is also partially attributable to higher throughput volumes on our CHOPS pipeline in the current year.

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Refinery Services Segment

Operating results for our refinery services segment were as follows:

	Year Ended December 31,	
	2014	2013
Volumes sold (in Dry short tons "DST"):		
NaHS volumes	150,038	147,297
NaOH (caustic soda) volumes	94,693	87,463
Total	244,731	234,760
Revenues (in thousands):		
NaHS revenues	$161,962	$159,125
NaOH (caustic soda) revenues	48,610	50,748
Other revenues	7,725	6,987
Total external segment revenues	$218,297	$216,860
Segment Margin (in thousands)	$84,851	$75,361
Average index price for NaOH per DST (1)	$589	$604
Raw material and processing costs as % of segment revenues	43 %	49 %

(1) Source: IHS Chemical

Refinery Services Segment Margin for 2014 increased $9.5 million, or 13%, from 2013. The significant components of this fluctuation were as follows:

- NaHS revenues increased 2% primarily due to a slight increase in volumes. The pricing in our sales contracts for NaHS includes adjustments for fluctuations in commodity benchmarks, freight, labor, energy costs and government indexes. The frequency at which these adjustments are applied varies by contract, geographic region and supply point.
- Our raw material costs related to NaHS decreased correspondingly to the decrease in the average index price for caustic soda. We were able to realize benefits from operating efficiencies at several of our sour gas processing facilities, our favorable management of the acquisition (including economies of scale) and utilization of caustic soda in our (and our customers') operations, and our logistics management capabilities.
- Caustic soda revenues decreased 4%, primarily due to a decrease in our sales price for caustic soda, which was partially offset by an increase in sales volumes. Although caustic sales volumes may fluctuate, the contribution to Segment Margin from these sales is not a significant portion of our refinery services activities. Caustic soda is a key component in the provision of our sulfur-removal service, from which we receive the by-product NaHS. Consequently, we are a very large consumer of caustic soda. In addition, our economies of scale and logistics capabilities allow us to effectively purchase additional caustic soda for re-sale to third parties. Our ability to purchase caustic soda volumes is currently sufficient to meet the demands of our refinery services operations and third-party sales.
- Average index prices for caustic soda decreased to $589 per DST during 2014 compared to $604 per DST during 2013. Those price movements affect the revenues and costs related to our sulfur removal services as well as our caustic soda sales activities. However, generally changes in caustic soda index prices do not materially affect Segment Margin attributable to our sulfur processing services because we usually pass those costs through to our NaHS sales customers. Additionally, our bulk purchase and storage capabilities related to caustic soda allow us to somewhat mitigate the effects of changes in index prices for caustic on our operating costs.

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Marine Transportation Segment

Within our marine transportation segment, we own a fleet of 71 barges (62 inland and 9 offshore) with a combined transportation capacity of 2.6 million barrels, 33 push/tow boats (24 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,	
	2014	2013
Revenues (in thousands):		
Inland freight revenues	$92,311	$80,536
Offshore freight revenues	82,732	28,164
Other rebill revenues (2)	54,239	43,842
Total segment revenues	$229,282	$152,542
Operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	$143,043	$104,816
Segment Margin (in thousands)	$86,239	$47,726
Fleet Utilization: (1)		
Inland Barge Utilization	97.5 %	99.2 %
Offshore Barge Utilization	99.6 %	99.8 %

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

(2) We are contractually able to rebill a certain portion of our operating costs to our customers.

Marine Transportation Segment Margin for 2014 increased $38.5 million, or 81%, from 2013. The significant components of this fluctuation were as follows:

- An increase in segment margin in 2014 due to a full year of operating results from our offshore marine transportation business, which we acquired in August 2013.
- The expansion of our inland marine fleet in 2014, with "new builds" including the addition of 8 inland barges and 2 inland pushboat in 2014.
- The acquisition of the M/T American Phoenix in late 2014, which became immediately accretive to Segment Margin at that time.

Utilization rates on our both our inland and offshore barge fleets did not change significantly in 2014 as compared to 2013.

Supply and Logistics Segment

Our supply and logistics segment is focused on utilizing our knowledge of the crude oil and petroleum markets to provide oil and gas producers, refineries and other customers with a full suite of services. Our supply and logistics segment owns or leases trucks, terminals, gathering pipelines, railcars, and rail loading and 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. These services include:

- utilizing the fleet of trucks, trailers and railcars owned or leased by our supply and logistics segment to transport products (primarily crude oil and petroleum products) for customers;
- utilizing various modes of transportation owned by third parties and us to transport products (primarily crude oil and petroleum products) for our own account to take advantage of logistical opportunities primarily in the Gulf Coast states and waterways;
- purchasing/selling and/or transporting crude oil from the wellhead to markets for ultimate use in refining;
- supplying petroleum products (primarily fuel oil, asphalt and other heavy refined products) to wholesale markets and some end-users such as paper mills and utilities;

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- purchasing products from refiners, transporting the products to one of our terminals and blending the products to a quality that meets the requirements of our customers and selling those products;
- railcar loading and unloading activities at our crude-by-rail terminals; and
- industrial gas activities, including wholesale marketing of CO_2 and processing of syngas through a joint venture.

We also 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 meeting their requirements and to purchase the crude oil and transport it to the refineries for sale. The imbalances and inefficiencies relative to meeting the refiners' requirements can provide opportunities for us to utilize our purchasing and logistical skills to meet their demands. The pricing in the majority of our purchase contracts contains a market price component and a deduction to cover the cost of transporting the crude oil 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 petroleum 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.

We utilize our fleet of 300 trucks, 400 trailers, 562 railcars, and 2.9 million barrels of leased and owned storage capacity to service our crude oil and refining customers and to store and blend the intermediate and finished refined products.

Operating results for our supply and logistics segment were as follows:

	Year Ended December 31,	
	2014	2013
	(in thousands)	
Supply and logistics revenue	$3,323,028	$3,689,795
Crude oil and products costs, excluding unrealized gains and losses from derivative transactions	(3,167,749)	(3,545,830)
Operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	(111,548)	(99,179)
Segment Margin attributable to discontinued operations	—	2,378
Other	(386)	1,230
Segment Margin	$43,345	$48,394
Volumetric Data (average barrels per day):		
Crude oil and petroleum products sales:		
Continuing operations	99,139	99,651
Discontinued operations	—	13,110
Total crude oil and petroleum products sales	99,139	112,761
Rail load/unload volumes (1)	32,559	19,721

(1) Indicates total barrels for which fees were charged for either loading or unloading at all rail facilities.

Segment Margin for our supply and logistics segment decreased $5 million or 10% , 2014 as compared to 2013. The decline is primarily attributable to $5 million in charges related to our planned exit of certain terminal facilities relating to our heavy fuel oil business, including non-recurring excess storage and tank cleaning costs from termination of certain storage facility leases with third parties.

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Crude and petroleum products volumes from continuing operations decreased slightly in 2014. In addition to this decrease, operating costs (excluding the above charges) increased 7% due to primarily to the recent growth in our crude oil rail loading and unloading and terminal operations. Segment margin was also negatively impacted by $2 million of 2013 margin pertaining to discontinued operations. Offsetting these factors was an improvement at managing our revenues and direct product costs in a volatile price environment in 2014.

The charge we took in our heavy fuel oil business is intended to allow us to "right size" that business prospectively to match the lower volumes of blend materials currently available for us to economically handle compared to the volumes that have historically been available to us. This new market reality has resulted, primarily, from the general lightening of refineries' crude slates resulting in a better supply/demand balance between heavy refined bottoms and domestic coker and asphalt requirements. In the first quarter of 2015, we will be exiting certain third-party terminal facilities historically leased to us to support our heavy fuel oil business.

Other Costs and Interest

General and administrative expenses

	Year Ended December 31,	
	2014	2013
	(in thousands)	
General and administrative expenses not separately identified below:		
Corporate	$39,445	$28,517
Segment	3,606	3,302
Equity-based compensation plan expense	5,111	9,180
Third party costs related to business development activities and growth projects	2,530	5,791
Total general and administrative expenses	$50,692	$46,790

Total general and administrative expenses increased $4 million between 2014 and 2013, primarily due to higher employee compensation expenses, as partially offset by decreases in equity-based compensation plan expense and third party costs related to business development activities and growth project. Third party costs related to business development activities and growth projects decreased $3.3 million due to the 2013 acquisition of our offshore marine transportation assets, during which time a significant amount of such costs were incurred. Decreases in the market price of our common units resulted in decreased expenses related to our equity-based compensation plans. The market price of our common units at December 31, 2014 was $42.42 compared to $52.57 at December 31, 2013, representing a 19% decrease, as compared to a 47% increase in the market price of our common units between December 31, 2013 and December 31, 2012. This was partially offset by an increase in the number of participants as of December 31, 2014 as compared to the number of participants as of December 31, 2013.

Depreciation and amortization expense

	Year Ended December 31,	
	2014	2013
	(in thousands)	
Depreciation on fixed assets	$73,230	$46,325
Amortization of intangible assets	13,436	14,560
Amortization of CO_2 volumetric production payments	4,242	3,899
Total depreciation and amortization expense	$90,908	$64,784

Total depreciation and amortization expense increased $26.1 million between 2014 and 2013 primarily as a result of placing newly acquired and constructed assets in service during calendar 2014 and the later part of 2013. This increase is partially offset by decreases in amortization of intangible assets. Depreciation expense increased $26.9 million primarily as a result of the 2013 acquisition of our offshore marine transportation assets and recently completed internal growth projects. Amortization of intangible assets decreased $1.1 million. A significant portion of our intangible assets were acquired in 2007 and are being amortized in relation to the benefit they provide to future cash flows, which is typically greater in the years closer to the period of acquisition.

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Interest expense, net

	Year Ended December 31,	
	2014	2013
	(in thousands)	
Interest expense, senior secured credit facility (including commitment fees)	$15,592	$11,949
Interest expense, senior unsecured notes	60,047	45,619
Amortization and write-off of debt issuance costs and premium	4,785	4,339
Capitalized interest	(13,785)	(13,324)
Net interest expense	$66,639	$48,583

Net interest expense increased $18.1 million during 2014 primarily due to an increase in our average outstanding indebtedness from newly acquired and constructed assets. In May 2014, we issued an additional $350 million of aggregate principal amount of 5.625% senior unsecured notes to repay borrowings under our senior secured credit facility. Capitalized interest costs increased slightly in 2014 due to our growth capital expenditures when compared to the prior year.

Year Ended December 31, 2013 Compared with Year Ended December 31, 2012

Onshore Pipeline Transportation Segment

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

	Year Ended December 31,	
	2013	2012
	(in thousands)	
Crude oil tariffs and revenues from direct financing leases—onshore crude oil pipelines	$39,627	$31,931
CO_2 tariffs and revenues from direct financing leases of CO_2 pipelines	26,342	26,603
Sales of crude oil pipeline loss allowance volumes	11,526	9,165
Onshore pipeline operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	(19,217)	(15,607)
Payments received under direct financing leases not included in income	5,110	5,016
Other	961	931
Segment Margin	$64,349	$58,039
Volumetric Data (average barrels/day unless otherwise noted):		
Onshore crude oil pipelines:		
Texas	51,067	51,880
Jay	34,933	22,306
Mississippi	18,026	18,711
Louisiana	—	—
Onshore crude oil pipelines total	104,026	92,897
CO_2 pipeline (average Mcf/day):		
Free State	190,274	186,479

During 2013, crude oil volumes shipped on our Jay System increased 12,627 barrels per day (or 57%). Additional barrels received at our new crude-by-rail unloading terminal at Walnut Hill, Florida, increased volumes on the Jay System.

Segment Margin for our onshore pipeline transportation segment increased $6.3 million, or 11%, in 2013 as compared to 2012. The significant components of this change were as follows:

- Crude oil tariff revenues of onshore crude oil pipelines increased $7.7 million, or 24%, primarily due to (1) upward tariff indexing of approximately 4.6% for our FERC-regulated pipelines effective in July 2013 and (2) a net increase in throughput volumes of 12,627 barrels per day primarily from our Jay pipeline system primarily from additional barrels received at our crude-by-rail unloading terminal at Walnut Hill, Florida.

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- Onshore crude oil pipeline loss allowance volumes, collected and sold, improved Segment Margin by $2.4 million due to an increase in barrels transported in 2013 compared to 2012.
- Pipeline operating costs, excluding non-cash charges, increased $3.6 million, due to pipeline integrity maintenance expenditures on the pipelines, employee compensation and related benefit costs and general increases in operating costs inclusive of safety program costs.

Offshore Pipeline Transportation Segment

Our offshore pipeline transportation segment is comprised of interests in five offshore pipeline systems and related assets, including four joint ventures which we account for under the equity method of accounting. One of our wholly-owned subsidiaries (GEL Offshore Pipeline, LLC, or "GOPL") owns our undivided joint interest in the Eugene Island pipeline system. Segment Margin for our Offshore Pipeline Transportation Segment as disclosed below primarily consists of distributions received based on our ownership percentage in each of our four offshore pipeline joint ventures. These distributions typically correlate with volumes transported, as rates per barrel do not materially fluctuate between periods.

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

	Year Ended December 31,	
	2013	2012
	(in thousands)	
Segment Margin (1)	$44,530	$38,500
Volumetric Data (average barrels/day unless otherwise noted):		
Offshore crude oil pipelines:		
CHOPS (2)	143,854	96,664
Poseidon (2) (3)	207,372	211,375
Odyssey (2) (3)	44,978	36,157
GOPL (3)	8,583	15,191
SEKCO (2)	—	—
Offshore crude oil pipelines total	404,787	359,387

(1) Offshore Pipeline Transportation segment margin includes approximately $44 million and $37 million of distributions received from our offshore pipeline joint ventures accounted for under the equity method of accounting in 2013 and 2012, respectively.
(2) Volumes for our equity method investees are presented on a 100% basis.
(3) Acquired in January 2012.

Segment Margin for our onshore pipeline transportation segment increased $6.0 million, or 16%, in 2013 as compared to 2012, primarily reflecting an increased contribution from CHOPS. CHOPS crude oil volumes increased by 47,190 barrels per day during 2013 due to the completion of improvement facility work by producers at the connected production fields in 2012 resulted in higher volumes transported on CHOPS in 2013. This was partially offset by a slight net decrease in crude oil volumes per day on our other offshore pipeline systems.

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Refinery Services Segment

Operating results for our refinery services segment were as follows:

	Year Ended December 31,	
	2013	2012
Volumes sold (in DST):		
NaHS volumes	147,297	142,712
NaOH (caustic soda) volumes	87,463	77,492
Total	234,760	220,204
Revenues (in thousands):		
NaHS revenues	$159,125	$153,689
NaOH (caustic soda) revenues	50,748	44,322
Other revenues	6,987	7,099
Total external segment revenues	$216,860	$205,110
Segment Margin (in thousands)	$75,361	$72,883
Average index price for NaOH per DST [(1)]	$604	$575
Raw material and processing costs as % of segment revenues	49 %	48 %

(1) Source: IHS Chemical

Refinery services Segment Margin for 2013 increased $2.5 million, or 3%, from 2012. The significant components of this fluctuation were as follows:

- NaHS revenues increased primarily as a function of increased sales volumes and an increase in the average index price for caustic soda (which is a component of our sales price), partially offset by other components referenced below. In 2013, NaHS sales volumes increased 3% primarily due to increased demand from customers in the pulp and paper industry, however this increase was partially offset by a decrease in sales to South American customers (due to timing of bulk deliveries). The pricing in our sales contracts for NaHS includes adjustments for fluctuations in commodity benchmarks, freight, labor, energy costs and government indexes. The frequency at which these adjustments are applied varies by contract, geographic region and supply point. The mix of NaHS sales volumes to which these adjustments applied reduced NaHS revenues in 2013.
- Our raw material costs related to NaHS increased correspondingly to the rise in the average index price for caustic soda, although we were able to partially offset our increased raw materials costs with operating efficiencies at several of our sour gas processing facilities, our favorable management of the acquisition (including economies of scale) and utilization of caustic soda in our (and our customers') operations, and our logistics management capabilities.
- Caustic soda sales volumes increased 13%. Although caustic sales volumes may fluctuate, the contribution to Segment Margin from these sales is not a significant portion of our refinery services activities. Caustic soda is a key component in the provision of our sulfur-removal service, from which we receive the by-product NaHS. Consequently, we are a very large consumer of caustic soda. In addition, our economies of scale and logistics capabilities allow us to effectively purchase additional caustic soda for re-sale to third parties. Our ability to purchase caustic soda volumes is currently sufficient to meet the demands of our refinery services operations and third-party sales.
- Average index prices for caustic soda increased to $604 per DST during 2013 compared to $575 per DST during 2012. Those price movements affect the revenues and costs related to our sulfur removal services as well as our caustic soda sales activities. However, generally changes in caustic soda prices do not materially affect Segment Margin attributable to our sulfur processing services because we usually pass those costs through to our NaHS sales customers. Additionally, our bulk purchase and storage capabilities related to caustic soda allow us to somewhat mitigate the effects of changes in index prices for caustic on our operating costs.

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Marine Transportation Segment

Operating results for the marine transportation segment were as follows:

	Year Ended December 31,	
	2013	2012
Revenues (in thousands):		
Inland freight revenues	$80,536	$77,023
Offshore freight revenues	28,164	—
Other rebill revenues	43,842	41,181
Total segment revenues	$152,542	$118,204
Operating Costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	$104,816	$80,676
Segment Margin (in thousands)	$47,726	$37,528
Fleet Utilization: [1]		
Inland Barge Utilization	99.2 %	98.1 %
Offshore Barge Utilization	99.8 %	N/A

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

Marine Transportation Segment Margin for 2013 increased $10.2 million, or 27% from 2012. This increase in segment margin in 2013 is primarily due to the acquisition of our offshore marine transportation business, which we acquired in August 2013. Utilization rates on our inland barge fleet did not change significantly in 2013 as compared to 2012.

Supply and Logistics Segment

Operating results for our supply and logistics segment were as follows:

	Year Ended December 31,	
	2013	2012
	(in thousands)	
Supply and logistics revenue	$3,689,795	$2,976,850
Crude oil and products costs, excluding unrealized gains and losses from derivative transactions	(3,545,830)	(2,840,883)
Operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	(99,179)	(80,597)
Segment Margin attributable to discontinued operations	2,378	(846)
Other	1,230	859
Segment Margin	$48,394	$55,383
Volumetric Data (average barrels per day):		
Crude oil and petroleum products:		
Continuing operations	99,651	79,174
Discontinued operations	13,110	14,869
Total crude oil and petroleum products	112,761	94,043
Rail load/unload volumes [1]	19,721	3,909

(1) Indicates total barrels for which fees were charged for either loading or unloading at all rail facilities.

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As discussed above in "Revenues, Costs and Expenses and Income from Continuing Operations," the average market prices of crude oil and petroleum products increased slightly between 2013 and 2012. Fluctuations in these prices, however, have a limited impact on our Segment Margin.

Segment Margin for our supply and logistics segment decreased $7.0 million, or 13%, in 2013 as compared to 2012. Crude and petroleum products volumes from continuing operations increased 26% in 2013. Somewhat offsetting this increase, operating costs, excluding non-cash charges, increased 23% between 2013 and 2012 primarily due to employee compensation and related benefit costs. Increases in those costs are the result of a higher number of employees from our expanded trucking fleet and the recent growth in our crude oil rail loading and unloading operations. Segment Margin in 2013 was also adversely impacted by railcar rental and storage costs incurred in advance of completion dates on certain of our rail projects, ineffectiveness of hedging certain crude oil volumes and volumetric measurement losses.

Additionally, in the second half of 2013, fluctuations in commodity margins for some of our refined products resulted in a decision by us to postpone sales and carry products in inventory for longer periods. Our decisions, from time to time, to carry more or less product inventory than usual are often driven by dislocations in the prices/margins for the underlying commodities. While certain conditions that gave rise to challenges beginning in the latter half of 2013 somewhat ameliorated, the level of activity, relative to our past years of experience, had not fully recovered by the end of 2013, resulting in lower volumes handled at reduced margins. Given these changing fundamentals, our operations remain in the process of transitioning from a level and structure designed to operate within historical market conditions in terms of costs, size and type of activity. This transition, as previously noted, has continued into 2014. See previous discussion in comparing Supply and Logistics Segment Margin between 2014 and 2013 for further updates on our refined products business, including recent actions taken.

Other Costs and Interest

General and administrative expenses

	Year Ended December 31,	
	2013	2012
	(in thousands)	
General and administrative expenses not separately identified below:		
Corporate	$28,517	$30,753
Segment	3,302	3,291
Equity-based compensation plan expense	9,180	6,114
Third party costs related to business development activities and growth projects	5,791	1,679
Total general and administrative expenses	$46,790	$41,837

Total general and administrative expenses increased $5 million between 2013 and 2012, primarily due to increases in third party costs related to business and growth transactions. Third party costs related to business development activities and growth projects increased $4.1 million due to the acquisition of our offshore marine transportation assets and recently completed internal growth projects. General and administrative expenses also increased due to an increase in equity-based compensation plan expenses not included in Segment Margin. Increases in the market price of our common units resulted in increased expenses related to our equity-based compensation plans. The market price of our common units at December 31, 2013 was $52.57 compared to $35.72 at December 31, 2012, representing a 47% increase.

Depreciation and amortization expense

	Year Ended December 31,	
	2013	2012
	(in thousands)	
Depreciation on fixed assets	$46,325	$37,382
Amortization of intangible assets	14,560	19,930
Amortization of CO_2 volumetric production payments	3,899	3,838
Total depreciation and amortization expense	$64,784	$61,150

Total depreciation and amortization expense increased $3.6 million between 2013 and 2012 primarily as a result of an increasing asset base, partially offset by decreases in amortization of intangible assets. Depreciation expense increased $8.9 million primarily as a result of the acquisition of our offshore marine transportation assets and recently completed internal

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growth projects. Amortization of intangible assets decreased $5.4 million. A significant portion of our intangible assets were acquired in 2007 and are being amortized in relation to the benefit they provide to future cash flows, which is typically greater in the years closer to the period of acquisition.

Interest expense, net

	Year Ended December 31,	
	2013	2012
	(in thousands)	
Interest expense, senior secured credit facility (including commitment fees)	$11,949	$14,199
Interest expense, senior unsecured notes	45,619	26,578
Amortization and write-off of debt issuance costs and premium	4,339	4,037
Capitalized interest	(13,324)	(3,891)
Net interest expense	$48,583	$40,923

Net interest expense increased $7.7 million during 2013, primarily due to an increase in our average outstanding indebtedness from newly acquired and constructed assets. In February 2013, we issued an additional $350 million of aggregate principal amount of 5.75% senior unsecured notes to repay borrowings under our senior secured credit facility. Capitalized interest costs, which increased due to our capital expenditures and investments in the SEKCO pipeline joint venture (see below for more information), partially offset the increase in interest expense.

Other Consolidated Results

Income Taxes

A portion of our operations are owned by wholly-owned corporate subsidiaries that are taxable as corporations. As a result, a substantial portion of the income tax expense we record relates to the operations of those corporations, and will vary from period to period based on the percentage of our income or loss that is derived from those corporations. The balance of the income tax expense we record relates to state taxes imposed on our operations that are treated as income taxes under generally accepted accounting principles and foreign income taxes. During 2014 and 2013, we recorded income tax expense of $2.8 million and $0.8 million, respectively. In 2012, we recorded income tax benefit of $9.2 million. The benefit during 2012 is primarily due to the reversal of $8.2 million in uncertain tax positions as a result of tax audit settlements and the expiration of statutes of limitation.

Financial Measures

Segment Margin

We define Segment Margin, which is a "non-GAAP" measure because it is not contemplated by or referenced in accounting principles generally accepted in the U.S., also referred to as GAAP, 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.

A reconciliation of Segment Margin to income from continuing operations before income taxes is included in our segment disclosures in Note 12 to our Consolidated Financial Statements in Item 8. Our non-GAAP financial measure 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. We believe that investors benefit from having access to the same financial measures being utilized by management, lenders, analysts and other market participants.

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 GAAP. 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 schedule below provides a reconciliation of this non-GAAP financial measure to its most directly comparable GAAP financial measure - income from continuing operations. 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

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context; they should be considered in a broad context with other quantitative and qualitative information. Our Available Cash before Reserves measures is just one 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; and expectations for us, and certain information regarding some of our peers. Additionally, our board of 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.

Available Cash before Reserves

Purposes, Uses and Definition

Available Cash before Reserves, also referred to 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 as income from continuing operations as adjusted for specific items, the most significant of which are the addition of certain non-cash expenses (such as depreciation and amortization), the substitution of distributable cash generated by our equity investees in lieu of our equity income attributable to our equity investees, the elimination of gains and losses on asset sales (except those from the sale of surplus assets), unrealized gains and losses on derivative transactions not designated as hedges for accounting purposes, the elimination of expenses related to acquiring or constructing assets that provide new sources of cash flows and the subtraction of maintenance capital utilized, which is described in detail below.

Recent Change in Circumstances and Disclosure Format

We have implemented a modified format relating to maintenance capital requirements because of our expectation that our future maintenance capital expenditures may change 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 new 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. Historically, 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

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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.

Prospectively, 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 future 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 recently 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 new measure, maintenance capital utilized, that we believe is more useful in the determination of Available Cash before Reserves. Our maintenance capital utilized measure, which is described in more detail below, 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 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.

Because we have not historically used our maintenance capital utilized measure, our future maintenance capital utilized calculations will reflect the utilization of solely those maintenance capital expenditures incurred since December 31, 2013. Further, we do not have the actual comparable calculations for our prior periods, and we may not have the information necessary to make such calculations for such periods. And, even if we could locate and/or re-create the information necessary to make such calculations, we believe it would be unduly burdensome to do so in comparison to the benefits derived.

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Available Cash before Reserves for the years ended December 31, 2014, 2013 and 2012 was as follows:

	Year Ended December 31,		
	2014	2013	2012
	(in thousands)		
Income from continuing operations	$106,202	$84,004	$97,337
Depreciation and amortization	90,908	64,784	61,150
Cash received from direct financing leases not included in income	5,529	5,110	5,016
Cash effects of sales of certain assets and discontinued operations	272	1,910	773
Effects of distributable cash generated by equity method investees not included in income	31,093	23,889	24,464
Cash effects of legacy stock appreciation rights plan	(1,381)	(5,498)	(3,280)
Non-cash legacy stock appreciation rights plan expense (credit)	(1,996)	5,704	4,478
Non-cash executive equity award expense	—	—	500
Expenses related to acquiring or constructing growth capital assets	2,528	5,791	1,679
Unrealized loss on derivative transactions excluding fair value hedges, net of changes in inventory value	(1,413)	1,313	86
Maintenance capital expenditures [1]	—	(3,569)	(4,430)
Maintenance capital utilized [1]	(922)	—	—
Non-cash tax expense (benefit)	1,745	(152)	(9,222)
Other items, net	62	2,779	607
Available Cash before Reserves	$232,627	$186,065	$179,158

(1) In the first quarter of 2014, we changed our method of including maintenance capital in our calculation of Available Cash before Reserves to "maintenance capital utilized" rather than "maintenance capital expenditures". For a description of the term "maintenance capital utilized," please see the definition of the term "Available Cash Before Reserves" previously discussed.

Liquidity and Capital Resources

General

As of December 31, 2014, we believe our balance sheet and liquidity position remained strong. We had $438.8 million of borrowing capacity available under our $1 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;
- 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 the necessary funds on satisfactory terms.

In September 2014, we issued 4,600,000 Class A common units in a public offering at a price of $50.71 per unit. We received proceeds, net of underwriting discounts and offering costs, of approximately $225.7 million from that offering. We

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used those net proceeds for general partnership purposes, including the repayment of borrowings under our revolving credit facility. See Note 11 to our Consolidated Financial Statements for more information.

In June 2014, we amended and restated our $1 billion senior secured credit facility with a syndicate of banks to, among other things, extend the term of our credit facility to July 25, 2019. Additionally, we increased the accordion feature from $300 million to $500 million, giving us the ability to expand the size of the facility up to an aggregate of $1.5 billion for acquisitions or internal growth projects, subject to lender consent. The inventory financing sublimit tranche under our senior secured credit facility is $150 million, which is designed to allow us to more efficiently finance crude oil and petroleum products inventory in the normal course of our operations, by allowing us to exclude the amount of inventory loans from our total outstanding indebtedness for purposes of determining our applicable interest rate. Our credit facility does not include a “borrowing base” limitation except with respect to our inventory loans. At any one time, we can have up to $100 million in letters of credit outstanding under our facility. We had $10.8 million in letters of credit outstanding at December 31, 2014. Due to the revolving nature of loans under our credit facility, we may make additional borrowings and periodic repayments and re-borrowings until the maturity date. At December 31, 2014, we had $550.4 million borrowed under our credit facility, with $45.0 million of the borrowed amount designated as a loan under the inventory sublimit. Thus, the total amount available for borrowings under our credit facility at December 31, 2014 was $438.8 million.

On May 15, 2014, we issued an additional $350 million of aggregate principal amount of 5.625% senior unsecured notes. Those notes were sold at face value. Interest payments are due on June 15 and December 15 of each year, beginning December 15, 2014. Those notes mature on June 15, 2024. The net proceeds were used to repay borrowings under our credit facility and for general partnership purposes.

The notes were co-issued by Genesis Energy Finance Corporation (which has no independent assets or operations) and are fully and unconditionally guaranteed, subject to customary exceptions pursuant to the indentures governing our 2024 Notes, jointly and severally, by certain of our wholly-owned subsidiaries. We have the right to redeem the 2024 Notes at any time after June 15, 2019, at a premium to the face amount of the 2024 Notes that varies based on the time remaining to maturity on the 2024 Notes. Prior to June 15, 2017, we may also redeem up to 35% of the principal amount of the 2024 Notes for 105.625% of the face amount with the proceeds from an equity offering of our common units.

At December 31, 2014, long-term debt totaled $1.6 billion, consisting of $550.4 million outstanding under our credit facility (including $45.0 million borrowed under the inventory sublimit tranche) a $350.6 million carrying amount of senior unsecured notes due on December 15, 2018 and a $350 million carrying amount of senior unsecured notes due on February 15, 2021 and a $350 million carrying amount of senior unsecured notes due on June 15, 2024.

For additional information on our long-term debt and covenants see Note 10 to our Consolidated Financial Statements in Item 8.

Cash Flows from Operations

We generally utilize the cash flows we generate from our operations to fund our working capital needs. Excess funds that are generated are used to repay borrowings from our credit facility and to fund 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, and we do not 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 the products to one of our storage facilities for further blending or we sell the product 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.

The storage of crude oil and petroleum products can have a material impact on our cash flows from operating activities. In the month we pay for the stored oil or petroleum products, we borrow under our credit facility (or use cash on hand) to pay for the oil or petroleum 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 or petroleum products. Additionally, we may be required to deposit margin funds with the NYMEX when 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 $291.1 million and $138.4 million for 2014 and 2013, 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 and petroleum products can result in fluctuations in our working capital and therefore, our operating cash

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flows between periods as the cost to acquire a barrel of oil or products will require more or less cash. The increase in operating cash flow for 2014 compared to 2013 was primarily due to an increase cash earnings, as well as a decrease in working capital needs.

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.

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,		
	2014	2013	2012
		(in thousands)	
Capital expenditures for fixed and intangible assets:			
Maintenance capital expenditures:			
Onshore pipeline transportation assets	$4,633	$1,104	$376
Offshore pipeline transportation assets	1,543	—	—
Refinery services assets	1,963	608	1,183
Marine transportation assets	5,539	954	1,857
Supply and logistics assets	833	820	1,014
Information technology systems	474	83	—
Total maintenance capital expenditures	14,985	3,569	4,430
Growth capital expenditures:			
Onshore pipeline transportation assets	$41,978	$129,683	$58,969
Offshore pipeline transportation assets	20	—	40
Refinery services assets	422	2,650	1,509
Marine transportation assets	70,186	28,902	35,331
Supply and logistics	324,297	214,318	56,694
Information technology systems	2,165	2,341	1,631
Total growth capital expenditures	439,068	377,894	154,174
Total capital expenditures for fixed and intangible assets	454,053	381,463	158,604
Capital expenditures for business combinations, net of liabilities assumed:			
Acquisition of American Phoenix	157,000	—	—
Acquisition of offshore marine transportation assets	—	230,880	—
Offshore pipelines	—	—	205,576
Total business combinations capital expenditures	157,000	230,880	205,576
Capital expenditures related to equity investees [1]	36,076	94,286	63,749
Total capital expenditures	$647,129	$706,629	$427,929

(1) Amount represents our investment in the SEKCO pipeline joint venture (see below for more information).

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.

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Capital Expenditures for Acquisitions
We continue to pursue a growth strategy that requires significant capital. On November 13, 2014, we acquired the M/T American Phoenix from Mid Ocean Tanker Company for approximately $157 million.
See Note 3 to our Consolidated Financial Statements in Item 8 for further information related to that acquisition.
Growth Capital Expenditures
Total capital expenditures on projects under construction are estimated to be approximately $480 million in 2015 and in future periods, inclusive of expenditures incurred through December 31, 2014. We anticipate that approximately $250 million of that total will be spent in 2015. The most significant of these projects currently under construction are described below.
Acquisition of the M/T American Phoenix
On November 13, 2014, we acquired the M/T American Phoenix from Mid Ocean Tanker Company for $157 million, which became part of our offshore marine transportation business. The M/T American Phoenix is a modern double-hulled, Jones Act qualified tanker with 330,000 barrels of cargo capacity that was placed into service during 2012. That acquisition complements and further integrates our existing operations, including our inland barge business (comprised of 62 barges and 24 push/tow boats) and our offshore tank barge and tug business (comprised of 9 boats and 9 barges).
Inland Marine Barge Transportation Expansion
We ordered 12 new-build barges and 10 new-build push boats for our inland marine barge transportation fleet. We have accepted delivery of 8 of those barges and 2 of those push boats as of December 2014. We expect to take delivery of those remaining vessels periodically into 2016.
ExxonMobil Baton Rouge Project
We are improving existing assets and developing new infrastructure in Louisiana, including connecting to Exxon Mobil Corporation’s Baton Rouge refinery, one of the largest refinery complexes in North America, with more than 500,000 barrels per day of refining capacity. Our investment includes improving our existing terminal at Port Hudson, Louisiana, and building a new crude oil unit train unload facility at Scenic Station as well as constructing a new 17-mile 24-inch diameter crude oil pipeline connecting Port Hudson to the Baton Rouge Scenic Station and continuing downstream to the Exxon Mobil Anchorage Tank Farm. The Port Hudson upgrades and new crude oil pipeline were completed in the first quarter of 2014, and Scenic Station became operational in July 2014.
Baton Rouge Terminal
We are constructing a new crude oil, intermediates and refined products import/export terminal in Baton Rouge that will be located near the Port of Greater Baton Rouge and will be pipeline-connected to the port's existing deepwater docks on the Mississippi River. We will initially construct approximately 1.1 million barrels of tankage for the storage of crude oil, intermediates and/or refined products with the capability to expand to provide additional terminaling services to our customers. In addition, we will construct a new pipeline from the terminal that will allow for deliveries to existing Exxon Mobil facilities in the area, as well as connect our previously constructed 17-mile line to the terminal allowing for receipts from the Scenic Station Rail Facility. Shippers to Scenic Station will have access to both the local Baton Rouge refining market, as well as the ability to access other attractive refining markets via our Baton Rouge Terminal. The Baton Rouge Terminal is expected to be operational by the end of the third quarter of 2015.
Rail Projects
Walnut Hill - In 2013, we completed construction on the second phase of our crude-by-rail unloading terminal at Walnut Hill, Florida, which includes a 100,000 barrel storage tank, related equipment and connections to our Jay System. In April 2014, we completed construction of an additional 110,000 barrel storage tank at our Walnut Hill, Florida crude-by-rail terminal, which will allow us to handle increased rail and pipeline demand. That terminal is connected to our Jay System and now includes 210,000 Barrels of capacity.
Wink - In April 2014, we completed construction on the second phase of our crude oil rail loading facility in Wink, Texas, which allows us to more efficiently load full unit trains. That facility was designed to move crude oil from West Texas to other markets and gives us the capability to load Genesis and third party railcars.

Natchez - During the first quarter of 2014, we completed construction on the second phase of our crude oil rail unloading/loading facility at our existing terminal located in Natchez, Mississippi, which provides an additional 60 railcar spots and additional heated tanks. That facility is designed to facilitate the movement of Canadian bitumen/dilbit to Gulf Coast markets via the Mississippi River. This facility has the capability to heat and unload bitumen/dilbit, load trucks, blend crude oil and load barges for distribution to refineries.

Raceland - The Raceland Rail Facility, a new crude oil unit train unloading facility capable of unloading up to two unit trains per day, which is located in Raceland, Louisiana, and will be connected to existing midstream infrastructure that will provide direct pipeline access to the Louisiana refining markets and is expected to be operational in the second half of 2015.

Capital Expenditures Related to Equity Investees

The SEKCO Pipeline, our 50/50 joint venture with Enterprise Products in the deepwater Gulf of Mexico, was completed in June of 2014 and has been made available to serve the Lucius oil and gas field in the southern Keathley Canyon area of the Gulf of Mexico. We have paid $36.1 million during 2014 for construction costs and anticipate any further capital expenditures as relating to the initial building of this pipeline to be minimal.

Maintenance Capital Expenditures

Maintenance capital expenditures have annually ranged between $3 million and $15 million. As we place more assets into service, particularly as relating to our marine transportation assets, our maintenance capital expenditures may continue to increase in future years. 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 consists generally of all of our cash receipts less cash disbursements adjusted for net changes to reserves. We have increased our distribution for each of the last thirty-eight quarters, including the distribution paid for the fourth quarter of 2014, as shown in the table below (in thousands, except per unit amounts). Each quarter, our board of directors determines the distribution amount, or available cash, per unit based upon various factors such as our operating performance, cash on hand, future cash requirements and the economic environment. As a result, the historical trend of distribution increases may not be a good indicator of future increases.

Distribution For	Date Paid	Per Unit Amount	Total Amount
2012			
4th Quarter	February 14, 2013	$0.4850	$39,390
2013			
1st Quarter	May 15, 2013	$0.4975	$40,405
2nd Quarter	August 14, 2013	$0.5100	$42,302
3rd Quarter	November 14, 2013	$0.5225	$46,344
4th Quarter	February 14, 2014	$0.5350	$47,453
2014			
1st Quarter	May 15, 2014	$0.5500	$48,783
2nd Quarter	August 14, 2014	$0.5650	$50,114
3rd Quarter	November 14, 2014	$0.5800	$54,112
4th Quarter	February 13, 2015 (1)	$0.5950	$56,542

(1) This distribution was paid on February 13, 2015 to unitholders of record as of February 2, 2015.

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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, 2014.

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)]	$—	$—	$901,039	$700,000	$1,601,039
Estimated interest payable on long-term debt [(2)]	90,767	171,344	106,039	110,523	478,673
Operating lease obligations	32,830	30,188	20,272	31,967	115,257
Unconditional purchase obligations [(3)]	244,512	—	—	—	244,512
Other Cash Commitments:					
Asset retirement obligations [(4)]	1,200	—	—	30,802	32,002
Total	$369,309	$201,532	$1,027,350	$873,292	$2,471,483

(1) Our credit facility allows us to repay and re-borrow funds at any time through the maturity date of July 25, 2019. We have $350 million in aggregate principal amount of senior unsecured notes that mature on December 15, 2018 (the "2018 Notes"), $350 million in aggregate principal amount of senior unsecured notes that mature on February 15, 2021 (the "2021 Notes") and $350 million in aggregate principal amount of senior unsecured notes that mature on June 15, 2024 (the "2024 Notes").

(2) Interest on our long-term debt under our credit facility is at market-based rates. The interest rates on our 2018, 2021 and 2024 Notes are 7.875%, 5.75% and 5.625%, respectively. The amount shown for interest payments represents the amount that would be paid if the debt outstanding at December 31, 2014 under our credit facility remained outstanding through the final maturity date of July 25, 2019 and interest rates remained at the December 31, 2014 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 and petroleum products are generally at market-based prices. For purposes of this table, estimated volumes and market prices at December 31, 2014 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 an undiscounted basis. The recorded asset retirement obligation on our balance sheet at December 31, 2014 was $14.8 million and is further discussed in Note 6 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

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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 3 to our Consolidated Financial Statements in Item 8 regarding further discussion regarding our acquisitions.

Depreciation and Amortization of Long-Lived Assets and Intangibles

In order to calculate depreciation and amortization we must estimate the useful lives of our fixed assets 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 and trade names 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.

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. 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 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. 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. One of our monitoring procedures is the comparison of our market capitalization to our book equity on a

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quarterly basis to determine if there is an indicator of impairment. As of December 31, 2014, our market capitalization exceeded the book value of our equity; therefore, since there were no events or changes in circumstances indicating impairment issues, we determined that it was not necessary to perform an interim assessment as of December 31, 2014. We did not have any goodwill impairments in 2014, 2013 or 2012.

For additional information regarding our goodwill, see Note 9 to our Consolidated Financial Statements in Item 8.

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 expense routine repairs and maintenance as they are incurred. For the major replacements and improvements we defer and amortize the costs over the length of time that the certification is supposed to last, which is generally the 5 year (60 month) internal inspection regulated by the US Coast Guard. Inherent in this process are judgments we make regarding whether the specific cost incurred is capitalizable and the period that the incurred cost will benefit.

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 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, 2014, we had 426,668 phantom units outstanding and recorded $8.8 million of expense during 2014. 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, 2014, we estimated approximately $4.9 million of remaining compensation costs to be recognized over a weighted average period of approximately one year for these awards. Changes in our assumptions may impact our liabilities and expenses related to these awards.

See Note 15 to our Consolidated Financial Statements in Item 8 for further discussion regarding our equity compensation plans.

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.

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, 2014, 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 Adopted

In May 2014, the Financial Accounting Standards Board ("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 will be effective for us beginning January 1, 2017 and early adoption is not permitted. The guidance permits the use of either a full retrospective or a modified retrospective approach. We are evaluating the transition methods and the impact of the amended guidance on our financial position, results of operations and related disclosures.

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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, NaHS and NaOH prices and interest rates. Our policy is to purchase only commodity products for which we have a market, and to structure our sales 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, 2014 were categorized as non-trading. On December 31, 2014 we had entered into NYMEX future contracts that will settle between January and March 2015 and NYMEX options contracts that will settle during February and March 2015. This accounting treatment is discussed further in Note 17 to our Consolidated Financial Statements.

The table below presents information about our open derivative contracts at December 31, 2014. 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, 2014 quoted market prices on the NYMEX. 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)
NYMEX Futures Contracts							
Sell (Short) Contracts:							
Crude Oil	Bbl	366	Bbl	$74.82	$27,385	$(6,974)	$20,411
Diesel	Bbl	56	Gal (1)	$2.43	$5,709	$(1,396)	$4,313
#6 Fuel Oil	Bbl	465	Bbl	$60.07	$27,934	$(8,012)	$19,922
Buy (Long) Contracts:							
Crude Oil	Bbl	168	Bbl	$65.30	$10,971	$(1,603)	$9,368
#6 Fuel Oil	Bbl	95	Bbl	$44.95	$4,270	$(209)	$4,061
NYMEX Option Contracts (2)							
Written Contracts:							
Crude Oil	Bbl	125	Bbl	$2.08	$260	$(498)	$(238)

(1) Prices and volumes as presented as quoted on the NYMEX. To calculate the total contract value the price per unit in gallons should be multiplied by 42 gallons to convert into a price per barrel.

(2) Weighted average premium received/paid.

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.

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, 2014, we had $550.4 million of debt outstanding under our credit facility. For the year ended December 31, 2014, a 10% change in LIBOR would have resulted in approximately a $1.3 million change in net income.

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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” on page 86.
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, 2014. 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, 2014, 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, 2014. Deloitte & Touche LLP, the Partnership’s independent registered public accounting firm, has issued an attestation report on the effectiveness of the Partnership’s internal control over financial reporting. Deloitte & Touche’s attestation report on the Partnership’s internal control over financial reporting appears in Item 8. “Financial Statements and Supplementary Data.”

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.

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As is common with MLPs, our partnership structure does not allow our unitholders to directly or indirectly participate in our management or operations. The board of directors of our general partner 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 the board of directors of our general partner (which we refer to as "our board of directors"), subject to the Davison family's rights 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 and the removal of our general partner.

Collectively, members of the Davison family own approximately 13.4% of our Class A Common Units and 76.9% of our Class B Common Units, for a combined ownership percentage of 13.5% of total Common Units. The Davison family is entitled to elect up to three directors under terms of its unitholders rights agreement. If members of the Davison family own (i) 15% or more of our common units, they have the right to appoint three directors, (ii) less than 15% but more than 10%, they have the right to appoint two directors, and (iii) less than 10%, they have the right to appoint one director. So long as the Davison family has the right to elect three directors, our board of directors cannot have more than 11 directors without the Davison family's consent.

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., Corbin J. Robertson III, 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. Robertson, 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. As a result, Mr. Sims serves as Chairman and Chief Executive Officer. 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.

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, 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

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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 weather . Management is responsible for the day-to-day management of 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 is 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 it is in our best interest for the interests of the members of our board of directors and certain of our officers to be aligned (when practical) 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 and/or held in broker margin accounts. See Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder 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 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 of Ms. Gasaway and Messrs. Albert and Taylor 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."

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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.

Directors and Executive Officers

Set forth below is certain information concerning our directors and executive officers, effective as of February 27, 2015.

Name	Age	Position
Grant E. Sims	59	Director, Chairman of the Board, and Chief Executive Officer
Conrad P. Albert	68	Director
James E. Davison	77	Director
James E. Davison, Jr.	48	Director
Sharilyn S. Gasaway	46	Director
Kenneth M. Jastrow II	67	Director
Corbin J. Robertson III	44	Director
Jack T. Taylor	63	Director
Robert V. Deere	60	Chief Financial Officer
Paul A. Davis	51	Senior Vice President
Stephen M. Smith	38	Vice President
Richard R. Alexander	39	Vice President
Karen N. Pape	56	Senior Vice President and Controller

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 had been a private investor since 1999. He was affiliated with Leviathan Gas Pipeline Partners, L.P. 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 an NYSE-listed MLP that merged with Enterprise Products Partners, L.P. on September 30, 2004. 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 refinery services businesses. Mr. Davison brings to our board of directors significant energy-related transportation and refinery services 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 Community Trust Financial Corporation and serves on its nominating and corporate governance, finance, and compensation 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.

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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 nominating committee of JB Hunt and the nominating and corporate governance committee and investment committees 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 chairperson of the G&C Committee. Mr. Jastrow is Non-Executive Chairman of Forestar Group, Inc., a real estate and natural resources company. He 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’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.

Corbin J. Robertson III has served as a director of our general partner since February 2010. Mr. Robertson is a Managing Partner of LKCM Headwater Investments GP, LLC and LKCM Headwater Investments I, L.P., a private equity fund. Mr. Robertson is also an owner of various interests associated with the Robertson family holding company and Quintana Capital Group, an energy focused private equity firm he co-founded. Mr. Robertson currently serves on various boards of Quintana and LKCM Headwater affiliated portfolio companies. Previously, Mr. Robertson was a Vice President for Reservoir Capital Group, a New York-based investment firm, and prior to that, he worked for three years as a Vice President for Sandefer Capital Partners, an energy investment fund. We believe that Mr. Robertson's experience with investment in a variety of energy businesses provides a valuable resource to our board of directors.

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 the 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.

Paul A. Davis has served as Senior Vice President of our general partner since March 2012. Mr. Davis is responsible for the commercial development of Genesis. Mr. Davis spent approximately 19 years in the investment banking industry with a focus in the midstream and master limited partnership sector, serving in various roles, including Managing Director at Bank of America Merrill Lynch.

Stephen M. Smith has served as Vice President of our general partner since February 2010. Mr. Smith is responsible for the commercial aspects of our Supply and Logistics segment. Since 2009, Mr. Smith has served in various capacities within our commercial development and finance groups. He was a Principal for the energy investment banking group at Banc of America Securities from 2006 to 2009.

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.

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.”

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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, except that Mr. Alexander filed an initial Form 3 on February 18, 2015 to report his holdings after being named an executive officer on November 13, 2014.

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, 2014.
Compensation Discussion and Analysis
Named Executive Officers
Our NEOs for 2014 were:
- Grant E. Sims, Chief Executive Officer;
- Robert V. Deere, Chief Financial Officer;
- Paul A. Davis, Senior Vice President;
- Stephen M. Smith, Vice President; and
- Richard R. Alexander, 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, a majority of the members of which are "independent," according to NYSE listing standards, the authority and responsibility to regularly analyze and reconsider 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" 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 by the G&C Committee are effectively determinations by our board of directors. 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 as to their compensation. The CEO's proposal is based on (among other things) our financial results for the prior year, the individual executive's areas of responsibility, market data provided by our independent compensation adviser as well as recommendations from that 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 with our board of directors regarding compensation of our NEOs. 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.

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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 and long-term incentive awards are made or granted. Bonuses are paid in March of the year following the year in which they are earned.

Role of Compensation Consultant and Peer Group Analysis

The G&C Committee's charter authorizes the Committee 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 2014, the G&C Committee engaged BDO, an independent compensation consultant, to assist the 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 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 2014 consisted of the following 16 companies in the energy industry: Atlas Pipeline Partners, Buckeye Partners, Calumet Specialty Products Partners, Plains All American Pipeline, Crosstex Energy Partners, DCP Midstream Partners, Eagle Rock Energy Partners, HollyFrontier Corporation, Magellan Midstream Partners, Markwest Energy Partners, NuStar Energy, PVR Partners, Regency Energy Partners, Sunoco Logistics Partners, Targa Resources Partners and Western Refining. 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 and comparable growth or capital programs to us.

The 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 2014 peer group is different from the 2013 group because Copano Energy was removed and Plains All American Pipeline was added in Copano's place following Copano's acquisition by Kinder Morgan.

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 cash distributions 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 compensating 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 targeted 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.

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

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compensation include annual cash incentive 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-term and long-term incentives, cash and non-cash based compensation and an 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 business decisions and actions lead to the long-term growth and sustainability of the organization. Our bonus plan is driven by the generation of Available Cash before Reserves (which is an important metric of value for our unitholders) and our safety record. Our long term incentive plan is linked primarily to increases in the distribution rate on our common units and the appreciation in our common unit price, which we believe links pay with performance and creates an alignment of interest between our NEOs and our unitholders.

Elements of Our Compensation Program and Compensation Decisions for 2014

The primary elements of our compensation program are a combination of annual cash and long-term equity-based incentive compensation. For the year ended December 31, 2014, the elements of our compensation program for the NEOs consisted of the following:

- annual cash base salary
- discretionary annual cash 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, as well as 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 2014, 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 and, as a result, approved market adjustments for the following NEOs: Mr. Davis' salary was increased 15% to $375,000, and Mr. Smith's salary was increased 9% to $300,000. The G&C Committee determined that such increases were necessary to align salaries to comparable market levels and were warranted in light of their individual performance and increased levels of responsibility related to the management of the company. Mr. Sims' and Mr. Deere's salaries of $525,000 and $450,000, respectively, were not increased in 2014. Mr. Alexander's salary during 2014 was $300,000.

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Bonuses

Our NEOs 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 set following the analysis of market practices of the peer group and consideration of the level of salary and targeted long-term incentives for each NEO. For 2014, the G&C Committee set each NEO’s bonus target as a percentage of salary as follows:

Name	2014 Bonus Target (% of base salary)
Grant E. Sims	100%
Robert V. Deere	75%
Paul A. Davis	100%
Stephen M. Smith	100%
Richard R. Alexander	100%

We believe the Bonus Plan generates a bonus that represents a meaningful level of compensation for the employee population and encourages employees to operate as a unified team to generate results that are aligned with the interests of our unitholders. The G&C Committee therefore designed the Bonus Plan to enhance our financial performance by rewarding our NEOs and other employees for achieving (i) financial performance and (ii) safety objectives. Attainment of these two goals is measured by, respectively, Available Cash before Reserves (before subtracting bonus expense and related employer tax burdens) and company-wide safety incident rates.

Available Cash before Reserves, which is a "non-GAAP" measure, is an important factor in determining the amount of distributions to our unitholders and is a significant factor in the market’s perception of the value of common units of an MLP (See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for a description of Available Cash before Reserves.) Safety objectives encourage our employees to focus on the impact their job performance has on the environment in which we operate. Both of these measures are used to calculate the recommended bonus payout (or general bonus pool) described below. However, bonuses are paid at the discretion of the G&C Committee based on quantitative and qualitative measures relating to: our financial and operational performance relative to our peers; industry expectations; progress in attaining strategic goals; and individual performance. Because the determination of whether bonuses will be paid each year and in what amounts they will be paid is determined by the G&C Committee on a company-wide basis, NEOs only receive bonuses if other employees receive bonuses.

As in prior years, the 2014 general bonus pool was weighted and calculated as follows: the level of Available Cash before Reserves generated for the year as a percentage of a target set by the G&C Committee was weighted 90% and the achieved level of the safety incident rate was weighted 10%. The sum of the weighted percentage achievement of these targets was multiplied by the eligible compensation and the target percentages established by the G&C Committee for the various levels of our employees to determine the maximum general bonus pool. In addition, the G&C Committee also considered other subjective factors in determining the general bonus pool and individual award amounts.

The total 2014 pool approved for such bonuses, inclusive of other discretionary downward adjustments, was approximately $8 million. Messrs. Davis, Smith, and Alexander were award bonuses of $225,000, $150,000 and $300,000 respectively in recognition of their leadership of their respective areas of responsibility. The bonuses were approved based on the G&C Committee's subjective review of the operational and financial performance of the company, industry expectations and individual performance. The bonuses will be paid in March 2015. Messrs. Sims and Deere voluntarily elected not to be considered for a bonus.

Long-Term Incentive Compensation

We provide equity-based, long-term compensation for employees, including executives and directors, through our 2010 Long-Term Incentive Plan, or the 2010 LTIP. The 2010 LTIP is designed to promote a sense of proprietorship and personal involvement in our development and financial success among our employees and directors through awards of phantom units and distribution equivalent rights, or DERs. The 2010 LTIP also allows for providing flexible incentives to employees and directors. Prior to vesting or termination of the applicable restricted period, our officers cannot transfer (including sale, pledge or hedge) any of their LTIP Awards. The 2010 LTIP provides for the awards of phantom units and DERs to directors of our general partner, and employees and other representatives of our general partner and its affiliates who provide services to us.

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All long-term objectives for payments to participants in the 2010 LTIP are based upon measurable performance targets. These targets consist of specific increases in the distributions paid to unitholders. As a result, we believe that the 2010 Long-Term Incentive Plan strongly aligns the interests of management with those of our unitholders.

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.

The G&C Committee administers the 2010 LTIP. Under the 2010 LTIP, the G&C Committee (at its discretion) has the authority to determine the terms and conditions of any awards granted under the 2010 LTIP and to adopt, alter and repeal rules, guidelines and practices relating to the 2010 LTIP. The G&C Committee has full discretion to administer and interpret the 2010 LTIP and to establish such rules and regulations as it deems appropriate and to determine, among other things, the time or times at which the awards may be exercised and whether and under what circumstances an award may be exercised. The G&C Committee designates participants in the 2010 LTIP, determines the types of awards to grant to participants and determines the number of units to be covered by any award. Our board of directors can terminate the 2010 LTIP at any time.

Targeted grant values for the NEOs are set following the analysis of market practices of the peer group and consideration of the level of salary and targeted bonus for each NEO. For 2014, the G&C Committee established the following long-term incentive target grant values for each of our NEOs:

Name	2014 Long-Term Incentive Target Grant Value
Grant E. Sims	$ 400,000
Robert V. Deere	$ 400,000
Paul A. Davis	$ 600,000
Stephen M. Smith	$ 400,000
Richard R. Alexander	$ 300,000

In April 2014, phantom units were granted to each of our NEOs and certain non-officer employees under the 2010 LTIP. The number of units granted was determined by dividing the average 20-day closing price of our units through the date of grant by the long-term incentive target amount. The phantom units will be paid in cash upon vesting based on the average closing price of the common units for the 20 trading days immediately prior to the date of vesting. The phantom units granted to our NEOs in April 2014 were all performance-based awards with the exception of Mr. Alexander. Phantom units granted to our non-officer employees, as well as Mr. Alexander, were apportioned 60% to performance-based awards and 40% to service-based awards. The service-based awards vest on the third anniversary from the date of grant.

Performance-based awards granted to our NEOs and non-officer employees will vest on the third anniversary of issuance, in an amount ranging from 50% to 150% of the targeted number of phantom units for each such NEO or non-officer employee, if certain quarterly cash distribution targets are achieved in the fourth quarter of 2016. In order to align the interests of our NEOs with our common unitholders and incentivize the NEOs to meet targeted distribution annual growth rates ranging between approximately 5% and 9% (which are deemed achievable growth rates by the G&C Committee), these awards will vest as follows:

(i) if the quarterly cash distribution on the common units for the fourth quarter of 2016 is $0.60 per unit, 50% of the target number of phantom units granted will vest, and the remainder will be forfeited;

(ii) if the quarterly cash distribution on the common units is $0.65 per unit, 100% of the target number of phantom units granted will vest; or

(iii) if the quarterly cash distribution on the common units is $0.70 per unit or greater, 150% of the target number of phantom units granted will vest.

Should the quarterly cash distribution on the common units fall between the range of $0.60 per unit and $0.70 per unit, the phantom units will vest between 50% and 150% of the number targeted on a proportionately adjusted basis (for example, if the quarterly cash distribution on the common units is $0.63 per unit, 75% of the phantom units targeted will vest or if the quarterly cash distribution on the common units is $0.6750 per unit, 125% of the phantom units targeted will vest). If the quarterly cash distribution is below $0.60 per unit for the fourth quarter of 2016, all of the performance-based phantom units granted will be forfeited.

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The phantom units also include distribution equivalent rights, or DERs, which are granted in tandem with all phantom units. DERs on service-based awards to our non-officer employees will be paid quarterly in connection with the related phantom units. DERs on all granted performance-based awards to our NEOs are accumulated and paid upon vesting when the number of phantom units earned is determined.

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, and we do not provide post-retirement medical benefits to our employees.

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

Tax and Accounting Implications

Because we are a partnership and not a corporation for federal income tax purposes, we are not subject to the limitations of Internal Revenue Code Section 162(m) with respect to tax-deductible executive compensation. However, if such tax laws related to executive compensation change in the future, the G&C Committee will consider the implication of such changes to us.

For our equity-based compensation arrangements, we record compensation expense over the vesting period of the awards, as discussed further in Note 15 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 the review and discussions, 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
Corbin J. Robertson III
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;
- goals are appropriately set to avoid targets that, if not achieved, result in a large percentage loss of compensation;
- incentive awards are capped by the G&C Committee;

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- 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 2014, 2013 and 2012.

Name & Principal Position	Year	Salary ($)	Bonus ($) (1)	Stock Awards ($) (2)	All Other Compensation ($) (5)	Total ($)
Grant E. Sims	2014	$525,000	$—	$401,163	$182,187	$1,108,350
Chief Executive Officer	2013	517,308	—	1,248,181	196,119	1,961,608
(Principal Executive Officer)	2012	492,308	425,000	1,198,716	147,882	2,263,906
Robert V. Deere	2014	450,000	—	401,163	102,482	953,645
Chief Financial Officer	2013	446,923	—	499,291	104,808	1,051,022
(Principal Financial Officer)	2012	433,846	200,000	468,817	77,737	1,180,400
Paul A. Davis (3)	2014	359,615	350,000	601,718	63,838	1,375,171
Senior Vice President	2013	311,154	250,000	424,374	33,843	1,019,371
	2012	215,385	200,000	500,000	10,581	925,966
Stephen M. Smith	2014	292,308	150,000	401,163	65,071	908,542
Vice President	2013	267,308	—	324,563	59,079	650,950
	2012	240,769	250,000	332,973	56,343	880,085
Richard R. Alexander (4)	2014	295,192	300,000	300,859	54,619	950,670
Vice President						

(1) For 2014, Mr. Davis received a retention bonus of $125,000 and a bonus of $225,000.

(2) 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, excluding the amount shown for Mr. Davis. The 2012 amount for Mr. Davis represents the grant date fair value of an award of 12,206 Class A Units and 2,946 Waiver Units issued on the first day of Mr. Davis' employment in March 2012. 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 15 to our Consolidated Financial Statements in Item 8.

(3) Mr. Davis became an executive officer of our general partner in March 2012.

(4) Mr. Alexander became an executive officer of our general partner in November 2014.

(5) The following table presents the components of "All Other Compensation" for each NEO for the year ended December 31, 2014.

Name	401(k) Matching and Profit Sharing Contributions (a)	Insurance Premiums (b)	Other Compensation (c)	Totals
Grant E. Sims	$7,800	$1,458	$172,929	$182,187
Robert V. Deere	$23,400	$1,458	$77,624	$102,482
Paul A. Davis	$23,400	$1,458	$38,980	$63,838
Stephen M. Smith	$7,800	$1,428	$55,843	$65,071

Richard R. Alexander	$23,400	$1,428	$29,791	$54,619

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.

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Grants of Plan-Based Awards in Fiscal Year 2014

The following table shows equity incentive plan awards granted to our NEOs in 2014.

Name	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards [(1)] Threshold	Target	Maximum	Market Price of Common Units on Award Date [(2)]	Grant Date Fair Value of Stock and Option Awards [(3)]
Grant E. Sims	4/8/2014	3,704	7,407	11,111	$54.01	$401,163
Robert V. Deere	4/8/2014	3,704	7,407	11,111	$54.01	$401,163
Paul A. Davis	4/8/2014	5,555	11,110	16,665	$54.01	$601,718
Stephen M. Smith	4/8/2014	3,704	7,407	11,111	$54.01	$401,163
Richard R. Alexander	4/8/2014	3,889	5,555	7,222	$54.01	$300,859

(1) Represents the number of phantom units that each NEO can earn of grant awarded on April 9, 2014, if the company meets certain performance conditions (threshold, target and maximum) during the fourth quarter of 2016. See additional discussion in "Long-Term Incentive Compensation" above.

(2) Represents the closing market price of our common units on the date of the phantom unit award on April 9, 2014.

(3) The amounts in this column for each NEO represent the fair value of the award on the date of the grant (as calculated in accordance with accounting guidance for equity-based compensation) using the twenty day average closing price of our common units through the date of grant ($54.16).

Employment Agreements

Paul A. Davis

Mr. Davis entered into a letter agreement in March 2012, relating to his employment, providing for a base salary which is subject to discretionary upward adjustments. Currently, the annual base salary of Mr. Davis is $375,000. That agreement provides that Mr. Davis 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.

Richard R. Alexander

Mr. Alexander entered into an employment agreement in July 2008, relating to his employment, providing for a base salary which is subject to discretionary upward adjustments. Currently, the annual base salary of Mr. Alexander is $300,000. 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.

Grant E. Sims, Robert V. Deere, and Stephen M. Smith

Messrs. Sims, Deere and Smith do not have employment agreements with us.

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Outstanding Equity Awards at December 31, 2014

The following table presents the information regarding the outstanding equity awards to our NEOs at December 31, 2014.

Name	Grant Date	Stock Awards 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	4/8/2014	11,111	$459,107
	4/9/2013	39,861	$1,647,057
	4/10/2012	57,300	$2,367,636
Robert V. Deere	4/8/2014	11,111	$459,107
	4/9/2013	15,945	$658,847
	4/10/2012	22,410	$925,981
Paul A. Davis	4/8/2014	16,665	$688,598
	4/9/2013	13,553	$560,010
Stephen M. Smith	4/8/2014	11,111	$459,107
	4/9/2013	10,365	$428,282
	4/10/2012	15,917	$657,690
Richard R. Alexander (3)	4/8/2014	7,222	$298,413
	4/9/2013	6,910	$285,521
	4/10/2012	11,035	$455,966

(1) The number of performance units reflected in the table assumes a maximum performance payout based upon past achievement levels from the previous vesting period. For the service based units reflected in the table above, as only held by Mr. Alexander, the threshold, target, and maximum payouts are identical.

(2) The amounts in this column were calculated by multiplying the closing market price of our units using the twenty day average at year-end by the number of applicable units outstanding.

(3) Phantom units outstanding for Mr. Alexander include 2,222, 2,126 and 3,395 service based units for 2014, 2013 and 2012, respectively. The remainder of the outstanding units held by Mr. Alexander and represented above are performance based units.

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Phantom Units Vested

The following table presents the information regarding the vesting of phantom units during the year ended December 31, 2014 with respect to our NEOs.

Name	Phantom Unit Awards Number of Phantom Units Vested (#)	Value Realized on Vesting ($)
Grant E. Sims	44,660	$2,450,467
Robert V. Deere	22,565	$1,238,114
Stephen M. Smith	11,820	$648,563
Richard R. Alexander	3,380	$185,461
Paul A. Davis	—	$—

The phantom unit awards granted to our NEOs in 2011 vested on April 29, 2014 and, pursuant to our 2010 Long Term Incentive Plan, 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. Those phantom unit awards were paid in cash.

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 agreements of Messrs. Davis and Alexander provide certain compensation and benefits as an incentive for each of them to remain in our employ, enhancing our ability to call on and rely upon each of them in the event of a change of control. Neither of them would be entitled to severance benefits if terminated by our general partner 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

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

With respect to Mr. Davis, if within two years following a change of control he terminates his employment for good reason or his employment terminates for any reason other than his death, disability, good cause, or his voluntary resignation without good reason, Mr. Davis would be entitled to (i) continued health benefits for up to 18 months, (ii) a severance payment equal to the greater of (x) his annual base salary and (y) two times his annual base salary reduced by one-twelfth of his annual salary for each month he is employed following the change of control but prior to his termination; and (iii) a bonus payment equal to the greater of (x) 100% of his annual base salary and (y) 200% of his annual base salary reduced by one-twelfth of his annual salary for each month he is employed following the change of control but prior to his termination.

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

- "Good cause" means, in general, if the executive commits willful theft, embezzlement, forgery; conviction of similar criminal activity; willful violation of our material policies; or substantial non-performance of duties.
- "Change of control" means, in general, any sale or other transfer of substantially all of the assets of us or our general partner, other than to our affiliates, or any merger, consolidation, or other transaction pursuant to which more than 50% of our publicly-traded common units or more than 50% of our Class B Common Units ceases to be beneficially owned by the persons who owned such interests as of the date of the employment agreement.
- "Good reason" means, in general, the diminution of the executive's duties, title, reporting relationships, compensation, or benefits, or the relocation of our principal offices or the requirement that the executive be based anywhere other than the Houston, Texas area without his consent.

With respect to Mr. Alexander, if he terminates his employment for good reason or we terminate his employment without cause, Mr. Alexander 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, 2014, the termination benefits for Messrs. Sims, Deere, Davis, Smith and Alexander for voluntary termination or termination for cause would be zero.

Based upon a hypothetical termination date of December 31, 2014, 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	$300,000
Healthcare	22,607
Total	$322,607

If termination occurs due to death or disability, Messrs. Sims, Deere, Davis, Smith, and Alexander would vest in outstanding phantom unit awards under our 2010 LTIP. Utilizing the closing price of our common units for the twenty trading days prior to December 31, 2014 would result in payments under the 2010 LTIP of the following amounts upon death or disability:

Grant E. Sims	$2,982,519

Robert V. Deere	$1,362,610
Paul A. Davis	$832,391
Stephen A. Smith	$1,030,025
Richard R. Alexander	$799,873

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Based on a hypothetical simultaneous change of control and termination date of December 31, 2014, the change of control termination benefits for Messrs. Sims, Deere, Davis, Smith, and Alexander would have been as follows:

	Grant E. Sims	Robert V. Deere	Paul A. Davis	Stephen M. Smith	Richard R. Alexander
Severance pursuant to employment agreement	$—	$—	$1,500,000	$—	$300,000
Healthcare	—	—	33,911	—	22,607
Cash payment for vested phantom units under 2010 LTIP	2,982,519	1,362,610	832,391	1,030,025	799,873
Total	$2,982,519	$1,362,610	$2,366,302	$1,030,025	$1,122,480

Director Compensation in Fiscal Year 2014
The table below reflects compensation for the directors.

Name	Fees Earned or Paid in Cash ($) (1)	Stock Awards ($) (2) (3)	All Other Compensation ($) (4)	Total
James E. Davison	$ 80,000	$97,500	$ 14,556	$192,056
James E. Davison, Jr.	$ 80,000	$97,500	$ 14,556	$192,056
Sharilyn S. Gasaway	$ 102,500	$110,000	$ 16,482	$228,982
Kenneth M. Jastrow II	$ 92,500	$110,000	$ 15,944	$218,444
Corbin J. Robertson III	$ 80,000	$97,500	$ 14,663	$192,163
Conrad P. Albert	$ 92,500	$100,000	$ 4,655	$197,155
Jack T. Taylor	$ 92,500	$100,000	$ 4,655	$197,155

(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, 2014 consist of phantom units granted under our 2010 LTIP and stock appreciation rights pursuant to our Stock Appreciation Rights Plan. Messrs. James Davison and James Davison, Jr. each hold 6,111 outstanding phantom units and 1,000 stock appreciation rights. Messrs. Jastrow, Robertson, Albert, Taylor and Ms. Gasaway hold 6,746, 6,159, 2,779, 2,779 and 6,915 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. All phantom units awarded to directors vest on the third anniversary of the date of grant. 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 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 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.

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Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters
Securities Authorized for Issuance Under Equity Compensation Plans

	Number of securities remaining available for future issuance under equity compensation plans
Equity Compensation plans approved by security holders:	
2007 Long-term Incentive Plan (2007 LTIP)	832,928

There were no outstanding phantom units under this plan as of December 31, 2014, 2013 or 2012. For additional discussion of our 2007 LTIP, see Note 15 to our Consolidated Financial Statements in Item 8.

Beneficial Ownership of Partnership Units

The following table sets forth certain information as of February 27, 2015, 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			Class B Common Units	
	Amount and Nature of Beneficial Ownership (1)		Percent of Class	Amount and Nature of Beneficial Ownership	Percent of Class
Conrad P. Albert	5,000		*	—	—
James E. Davison	3,376,282	(2)	3.6 %	9,453	23.6 %
James E. Davison, Jr.	5,323,932	(3)	5.6 %	13,648	34.1 %
Sharilyn S. Gasaway	269,445		*	1,081	2.7 %
Kenneth M. Jastrow II	—		—	—	—
Corbin J. Robertson III	1,811,567	(4)	1.9 %	—	—
Jack T. Taylor	2,865		*	—	—
Grant E. Sims	2,987,947	(5)	3.1 %	7,087	17.7 %
Robert V. Deere	750,987		*	1,052	2.6 %
Paul A. Davis	15,152		*	—	—
Stephen M. Smith	416,144	(6)	*	—	—
Richard R. Alexander	10,000		*	—	—
Karen N. Pape	152,131		*	—	—
All directors and executive officers as a group (13 in total)	15,121,452		15.9 %	32,321	80.8 %
Steven K. Davison	2,392,839	(7)	2.5 %	7,676	19.2 %
Goldman Sachs Asset Management	5,890,187		6.2 %	—	—
OppenheimerFunds, Inc.	5,261,775		5.5 %	—	—
Alerian MLP ETF	5,017,333		5.3 %	—	—

*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 Davison Terminal Service, 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. Robertson pledged 1,512,555 of these Class A Common Units as collateral for margin accounts. Includes 198,785 Class A Common Units held by The Corbin J. Robertson III 2009 Family Trust and 5,743 Class A Common Units held by Corby & Brooke

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Robertson 2006 Family Trust. Also included are 20,000 Class A Common Units held by BHJ Investments, LP, whose members include Mr. Robertson, the Corby and Brooke Robertson 2014 Children's Trust, and Brooke Robertson as Mr. Robertson's wife.

(5) Mr. Sims pledged 866,334 of these Class A Common Units as collateral for loans from a bank. Includes 1,000 Class A Common Units held by Mr. Sims' father, of which Mr. Sims disclaims beneficial ownership.

(6) Mr. Smith pledged 275,000 Class A Common Units as collateral for margin brokerage accounts.

(7) 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.

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 $0.6 million, during 2014. 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 2014, Mr. Sims (our CEO and a director) had one son that worked as a non-executive employee in our business development department and another son that worked as a non-executive employee in our supply and logistics department. 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 non-executive employee in our supply and logistics department. Each of those respective family members received total W-2 compensation of greater than $120,000 but less than $350,000.

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. Robertson, 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.

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Item 14. Principal Accounting Fees and Services

The following table summarizes the fees for professional services rendered by Deloitte & Touche LLP for the years ended December 31, 2014 and 2013.

	2014	2013
	(in thousands)	
Audit Fees (1)	$2,489	$2,259
Audit-Related Fees (2)	—	23
Tax Fees (3)	839	879
All Other Fees (4)	8	6
Total	$3,336	$3,167

(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.
(2) Includes fees related to reviewing our documentation of controls and process for conversion related to our project to upgrade our information technology systems
(3) Includes fees for tax return preparation and tax consultations.
(4) Includes fees associated with licenses for accounting research software.

Pre-Approval Policy

The services by Deloitte in 2014 and 2013 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 Deloitte in 2014 and 2013, the audit committee determined that such services are compatible with the provision of independent audit services. The audit committee discussed these services with 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.

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Item 15. Exhibits and Financial Statement Schedules
(a)(1) Financial Statements
See “Index to Consolidated Financial Statements and Financial Statement Schedules” set forth on page 86.
(a)(2) Financial Statement Schedules.
See “Index to Consolidated Financial Statements and Financial Statement Schedules” set forth on page 86.
(a)(3) Exhibits

2.1	Purchase and Sale Agreement by and among Florida Marine Transporters, Inc., FMT Heavy Oil Transportation, LLC, FMT Industries, LLC, JAR Assets, Inc., Pasentine Family Enterprises, LLC, PBC Management, Inc., and GEL Marine, LLC dated June 24, 2011 (incorporated by reference to Exhibit 2.1 to the Company’s Current Report on Form 8-K dated June 30, 2011, File No. 001-12295).
2.2	Purchase and Sale Agreement, dated October 28, 2011, by and between Marathon Oil Company and Genesis Energy, L.P. regarding interest in Poseidon Oil Pipeline Company, L.L.C. (incorporated by reference to Exhibit 2.1 to the Company’s Current Report on Form 8-K dated January 9, 2012, File No. 001-12295).
2.3	Purchase and Sale Agreement, dated October 28, 2011, by and between Marathon Oil Company and Genesis Energy, L.P. regarding interest in Odyssey Pipeline L.L.C. (incorporated by reference to Exhibit 2.2 to the Company’s Current Report on Form 8-K dated January 9, 2012, File No. 001-12295).
2.4	Purchase and Sale Agreement, dated October 28, 2011, by and between Marathon Oil Company and Genesis Energy, L.P. regarding interests in Eugene Island Pipeline System and certain related pipelines (incorporated by reference to Exhibit 2.3 to the Company’s Current Report on Form 8-K dated January 9, 2012, File No. 001-12295).
2.5	Purchase and Sale Agreement, dated October 28, 2011, by and between Marathon Oil Company and Genesis Energy, L.P. regarding interests in Eugene Island Pipeline System and certain related pipelines (incorporated by reference to Exhibit 2.3 to the Company’s Current Report on Form 8-K dated January 9, 2012, 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	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).
3.5	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).
3.6	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).
3.7	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).
3.8	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	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).

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4.4	Amendment No. 1 to the 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 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	Indenture for 7.875% Senior Subordinated Notes due 2018, dated November 18, 2010 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 November 23, 2010, File No. 001-12295).
4.7	Supplemental Indenture for 7.875% Senior Subordinated Notes due 2018, dated as of November 24, 2010, 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 4.2 to the Company’s Registration Statement on Form S-4 dated September 26, 2011, File No. 333-177012).
4.8	Second Supplemental Indenture for 7.875% Senior Subordinated Notes due 2018, dated as of December 27, 2010, 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 4.3 to the Company’s Registration Statement on Form S-4 dated September 26, 2011, File No. 333-177012).
4.9	Third Supplemental Indenture for 7.875% Senior Subordinated Notes due 2018, dated as of February 28, 2011, 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 4.4 to the Company’s Registration Statement on Form S-4 dated September 26, 2011, File No. 333-177012).
4.10	Fourth Supplemental Indenture for 7.875% Senior Subordinated Notes due 2018, dated as of June 30, 2011, 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 4.5 to the Company’s Registration Statement on Form S-4 dated September 26, 2011, File No. 333-177012).
4.11	Fifth Supplemental Indenture for 7.875% Senior Subordinated Notes due 2018, dated as of September 13, 2011, 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 4.6 to the Company’s Registration Statement on Form S-4 dated September 26, 2011, File No. 333-177012).
4.12	Sixth Supplemental Indenture for 7.875% Senior Subordinated Notes due 2018, dated as of September 22, 2011, 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 4.7 to the Company’s Registration Statement on Form S-4 dated September 26, 2011, File No. 333-177012).
4.13	Seventh Supplemental Indenture for 7.875% Senior Subordinated Notes due 2018, dated as of December 5, 2011, 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 4.9 to Form 10-K filed on February 29, 2012, File No. 001-12295).
4.14	

	Eighth Supplemental Indenture for 7.875% Senior Subordinated Notes due 2018, dated as of January 3, 2012, 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 4.10 to Form 10-K filed on February 29, 2012, File No. 001-12295).
4.15	Ninth Supplemental Indenture for 7.875% Senior Subordinated Notes due 2018, dated as of January 27, 2012, 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 4.11 to Form 10-K filed on February 29, 2012, File No. 001-12295).
4.16	Tenth Supplemental Indenture for 7.875% Senior Subordinated Notes due 2018, dated as of December 6, 2012, 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 4.12 to Form 10-K filed on February 26, 2013, File No. 001-12295).
4.17	Eleventh Supplemental Indenture for 7.875% Senior Subordinated Notes due 2018, dated as of January 28, 2013, 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 4.13 to Form 10-K filed on February 26, 2013, File No. 001-12295).
4.18	Twelfth Supplemental Indenture for 7.875% Senior Subordinated Notes due 2018, 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). .

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*	4.19	Thirteenth Supplemental Indenture for 7.875% Senior Subordinated Notes due 2018, 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.
*	4.20	Fourteenth Supplemental Indenture for 7.875% Senior Subordinated Notes due 2018, 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.
*	4.21	Fifteenth Supplemental Indenture for 7.875% Senior Subordinated Notes due 2018, 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.
*	4.22	Sixteenth Supplemental Indenture for 7.875% Senior Subordinated Notes due 2018, 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.
*	4.23	Seventeenth Supplemental Indenture for 7.875% Senior Subordinated Notes due 2018, 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.
*	4.24	Eighteenth Supplemental Indenture for 7.875% Senior Subordinated Notes due 2018, 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.
	4.25	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).
	4.26	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). .
*	4.27	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.
*	4.28	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.
*	4.29	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.
*	4.30	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.
*	4.31	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.
*	4.32	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.
	4.33	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).
	4.34	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 10-K filed on May 15, 2014, File No. 001-12295).
*	4.35	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.
*	4.36	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.
*	4.37	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.

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*	4.38		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.
*	4.39		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.
	4.40		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).
	4.41		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).
	4.42		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 to Form 8-K dated November 16, 2007, File No. 001-12295).
	4.43		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 12, 2007, File No. 001-12295).
	4.44		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).
	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		Pipeline Financing Lease Agreement by and between Genesis NEJD Pipeline, LLC, as Lessor and Denbury Onshore, LLC, as Lessee for the North East Jackson Dome Pipeline dated May 30, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K dated June 5, 2008, File No. 001-12295).
	10.4		Transportation Services Agreement between Genesis Free State Pipeline, LLC, as Lessor and Denbury Onshore, LLC dated May 30, 2008 (incorporated by reference to Exhibit 10.3 to Form 8-K dated June 5, 2008, File No. 001-12295).
	10.5		Form of Indemnity Agreement, among Genesis Energy, L.P., Genesis Energy, LLC and Quintana Energy Partners II, L.P. 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).
	10.6	+	Genesis Energy, LLC First Amended and Restated Stock Appreciation Rights Plan (incorporated by reference to Exhibit 10.24 to the Company's Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-12295).
	10.7	+	Form of Stock Appreciation Rights Plan Grant Notice (incorporated by reference to Exhibit 10.25 to the Company's Annual Report on Form 10-K for the year ended December 31, 2008, File No.

		001-12295).
10.8	+	Genesis Energy, Inc. 2007 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K dated December 21, 2007, File No. 001-12295).
10.9	+	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).
10.10	+	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).
10.11	+	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).
10.12	+	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).
10.13	+	Form of 2007 Phantom Unit Grant Agreement (3-Year Graded) (incorporated by reference to Exhibit 10.2 to the Company’s Current Report on Form 8-K dated December 21, 2007, File No. 001-12295).

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	10.14	+	Form of 2007 Phantom Unit Grant Agreement (3-Year Cliff) (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K dated December 21, 2007, File No. 001-12295).
	10.15	+	Employment Agreement by and between Genesis Energy, LLC and Grant E. Sims, dated December 31, 2008 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated January 7, 2009, File No. 001-12295).
	10.16	+	Employment Agreement by and between Genesis Energy, LLC and Robert V. Deere, dated December 31, 2008 (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K dated January 7, 2009, File No. 001-12295).
	10.17	+	Employment Agreement by and between Genesis Energy, LLC and Paul A. Davis, dated March 5, 2012.
	10.18	+	Transition, Separation and General Release Agreement by and between Genesis Energy, LLC and Steven R. Nathanson, dated April 11, 2014 (incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K dated April 14, 2014, File No. 001-12295).
	10.19	+	Waiver Agreement (Sims), dated February 5, 2010 (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K dated February 11, 2010, File No. 001-12295).
	10.20		Waiver Agreement (Deere), dated February 5, 2010 (incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K dated February 11, 2010, File No. 001-12295).
	10.21		Purchase Agreement dated February February 5, 2013 relating to 5.750% Senior Notes due 2021 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated February 11, 2013, File No. 001-12295).
*	10.22	+	Employment Agreement by and between DG Marine Transportation, LLC and Richard Alexander dated July 18, 2008.
	11.1		Statement Regarding Computation of Per Share Earnings (See Notes 2 and 11 of the Notes to the Consolidated Financial Statements).
*	21.1		Subsidiaries of the Registrant.
*	23.1		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.
*	101.INS		XBRL Instance Document.
*	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.

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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 27, 2015

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 Grant E. Sims	Chairman of the Board, Director and Chief Executive Officer (Principal Executive Officer)	February 27, 2015
/s/ ROBERT V. DEERE Robert V. Deere	Chief Financial Officer, (Principal Financial Officer)	February 27, 2015
/s/ KAREN N. PAPE Karen N. Pape	Senior Vice President and Controller (Principal Accounting Officer)	February 27, 2015
/s/ CONRAD P. ALBERT Conrad P. Albert	Director	February 27, 2015
/s/ JAMES E. DAVISON James E. Davison	Director	February 27, 2015
/s/ JAMES E. DAVISON, JR. James E. Davison, Jr.	Director	February 27, 2015
/s/ SHARILYN S. GASAWAY Sharilyn S. Gasaway	Director	February 27, 2015
/s/ KENNETH M. JASTROW, II Kenneth M. Jastrow, II	Director	February 27, 2015
/s/ CORBIN J. ROBERTSON, III Corbin J. Robertson, III	Director	February 27, 2015
/s/ JACK T. TAYLOR Jack T. Taylor	Director	February 27, 2015

* Genesis Energy, LLC is our general partner.

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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.
Houston, Texas

We have audited the accompanying consolidated balance sheets of Genesis Energy, L.P. and subsidiaries (the "Partnership") as of December 31, 2014 and 2013, and the related consolidated statements of operations, partners' capital, and cash flows for each of the three years in the period ended December 31, 2014. We also have audited the Partnership's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership's management is responsible for these financial statements, 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 these financial statements and an opinion on the Partnership's internal control over financial reporting based on our audits.

We conducted our audits 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 and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Genesis Energy, L.P. and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
February 27, 2015

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

	December 31, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$9,462	$8,866
Accounts receivable—trade, net	271,529	368,033
Inventories	46,829	85,330
Other	27,546	72,994
Total current assets	355,366	535,223
FIXED ASSETS, at cost	1,899,058	1,327,974
Less: Accumulated depreciation	(268,057)	(199,230)
Net fixed assets	1,631,001	1,128,744
NET INVESTMENT IN DIRECT FINANCING LEASES, net of unearned income	145,959	151,903
EQUITY INVESTEES	628,780	620,247
INTANGIBLE ASSETS, net of amortization	82,931	62,928
GOODWILL	325,046	325,046
OTHER ASSETS, net of amortization	61,291	38,111
TOTAL ASSETS	$3,230,374	$2,862,202
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable—trade	$245,405	$316,204
Accrued liabilities	117,740	130,349
Total current liabilities	363,145	446,553
SENIOR SECURED CREDIT FACILITY	550,400	582,800
SENIOR UNSECURED NOTES	1,050,639	700,772
DEFERRED TAX LIABILITIES	18,754	15,944
OTHER LONG-TERM LIABILITIES	18,233	18,396
COMMITMENTS AND CONTINGENCIES (Note 19)		
PARTNERS' CAPITAL:		
Common unitholders, 95,029,218 and 88,690,985 units issued and outstanding at December 31, 2014 and 2013, respectively	1,229,203	1,097,737
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$3,230,374	$2,862,202

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

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

	Year Ended December 31, 2014	2013	2012
REVENUES:			
Pipeline transportation services	86,453	86,508	76,290
Refinery services	207,401	205,985	196,017
Marine transportation	229,282	152,542	118,204
Supply and logistics	3,323,028	3,689,795	2,976,850
Total revenues	3,846,164	4,134,830	3,367,361
COSTS AND EXPENSES:			
Supply and logistics product costs	3,166,336	3,547,141	2,840,970
Supply and logistics operating costs	110,716	102,187	82,776
Marine transportation operating costs	142,793	104,676	80,547
Refinery services operating costs	121,401	131,289	123,477
Pipeline transportation operating costs	30,767	27,206	21,894
General and administrative	50,692	46,790	41,837
Depreciation and amortization	90,908	64,784	61,150
Total costs and expenses	3,713,613	4,024,073	3,252,651
OPERATING INCOME	132,551	110,757	114,710
Equity in earnings of equity investees	43,135	22,675	14,345
Interest expense	(66,639)	(48,583)	(40,923)
Income from continuing operations before income taxes	109,047	84,849	88,132
Income tax (expense) benefit	(2,845)	(845)	9,205
Income from continuing operations	106,202	84,004	97,337
Income (loss) from discontinued operations	—	2,105	(1,018)
NET INCOME	$106,202	$86,109	$96,319
BASIC AND DILUTED NET INCOME PER COMMON UNIT:			
Continuing operations	$1.18	$1.00	$1.24
Discontinued operations	—	0.03	(0.01)
Net income per common unit	$1.18	$1.03	$1.23
WEIGHTED AVERAGE OUTSTANDING COMMON UNITS:			
Basic and Diluted	90,060	83,957	78,363

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

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

	Number of Common Units	Partners' Capital
December 31, 2011	71,965	$792,638
Net income	—	96,319
Cash distributions	—	(142,383)
Issuance of units for cash, net (Note 11)	5,750	169,421
Conversion of waiver units (Note 11)	3,476	—
Other	12	500
December 31, 2012	81,203	916,495
Net income	—	86,109
Cash distributions	—	(168,441)
Issuance of units for cash, net (Note 11)	5,750	263,574
Conversion of waiver units (Note 11)	1,738	—
December 31, 2013	88,691	1,097,737
Net income	—	106,202
Cash distributions	—	(200,461)
Issuance of common units for cash, net (Note 11)	4,600	225,725
Conversion of waiver units (Note 11)	1,738	—
December 31, 2014	95,029	$1,229,203

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

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GENESIS ENERGY, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31, 2014	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$106,202	$86,109	$96,319
Adjustments to reconcile net income to net cash provided by operating activities -			
Depreciation and amortization	90,908	64,796	61,166
Amortization and write-off of debt issuance costs and premium	4,785	4,339	4,037
Amortization of unearned income and initial direct costs on direct financing leases	(15,706)	(16,152)	(16,788)
Payments received under direct financing leases	21,235	21,262	21,804
Equity in earnings of investments in equity investees	(43,135)	(22,675)	(14,345)
Cash distributions of earnings of equity investees	57,165	34,132	23,900
Non-cash effect of equity-based compensation plans	4,494	12,473	7,197
Deferred and other tax benefits	1,745	(152)	(9,222)
Unrealized (gains) losses on derivative transactions	(17,984)	1,313	86
Other, net	3,391	(873)	2,085
Net changes in components of operating assets and liabilities, net of acquisitions (See Note 14)	77,954	(46,186)	13,065
Net cash provided by operating activities	291,054	138,386	189,304
CASH FLOWS FROM INVESTING ACTIVITIES:			
Payments to acquire fixed and intangible assets	(443,482)	(343,119)	(146,456)
Cash distributions received from equity investees—return of investment	18,363	12,432	14,909
Investments in equity investees	(40,926)	(94,551)	(63,749)
Acquisitions	(157,000)	(230,880)	(205,576)
Proceeds from asset sales and discontinued operations	272	1,910	773
Other, net	(1,214)	(1,622)	(1,508)
Net cash used in investing activities	(623,987)	(655,830)	(401,607)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings on senior secured credit facility	1,839,900	1,593,300	1,674,400
Repayments on senior secured credit facility	(1,872,300)	(1,510,500)	(1,583,700)
Proceeds from issuance of senior unsecured notes, including premium	350,000	350,000	101,000
Debt issuance costs	(11,896)	(8,157)	(7,105)
Issuance of common units for cash, net	225,725	263,574	169,421
Distributions to common unitholders	(200,461)	(168,441)	(142,383)
Other, net	2,561	(4,748)	1,135
Net cash provided by financing activities	333,529	515,028	212,768
Net increase (decrease) in cash and cash equivalents	596	(2,416)	465
Cash and cash equivalents at beginning of period	8,866	11,282	10,817
Cash and cash equivalents at end of period	$9,462	$8,866	$11,282

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

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GENESIS ENERGY, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
1. Organization
We are a limited partnership focused on the midstream segment of the oil and gas industry in the Gulf Coast region of the United States, primarily Texas, Louisiana, Arkansas, Mississippi, Alabama, Florida, Wyoming and in the Gulf of Mexico. We have a diverse portfolio of assets, including pipelines, refinery-related plants, storage tanks and terminals, railcars, rail loading and unloading facilities, barges 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.
In the fourth quarter of 2014, we reorganized our operating segments as a result of a change in the way our Chief Executive Officer, who is our chief operating decision maker, evaluates the performance of operations, develops strategy and allocates resources. The results of our marine transportation activities, formerly reported in the Supply and Logistics Segment, are now reported in our Marine Transportation Segment. In addition, the results of our offshore and onshore pipeline transportation activities, formerly reported in the Pipeline Transportation Segment, are now reported separately in our Onshore Pipeline Transportation Segment and Offshore Pipeline Transportation Segments.

As a result of the above changes, we currently manage our businesses through five divisions that constitute our reportable segments – Onshore Pipeline Transportation, Offshore Pipeline Transportation, Refinery Services, Marine Transportation and Supply and Logistics. Our disclosures related to prior periods have been recast to reflect our reorganized segments.

These five divisions that constitute our reportable segments consist of the following:
- Onshore pipeline transportation of crude oil and, to a lesser extent, carbon dioxide (or “CO_2”);
- Offshore pipeline transportation of crude oil in the Gulf of Mexico;
- Refinery services involving 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");
- Marine transportation to provide waterborne transportation of petroleum products and crude oil throughout North America; and
- Supply and logistics services, which include terminaling, blending, storing, marketing, and transporting crude oil and petroleum products and, on a smaller scale, CO_2.

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, 2014 and 2013 and our results of operations, changes in partners’ capital and cash flows for the years ended December 31, 2014, 2013 and 2012. 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 a 50% interest in Cameron Highway Oil Pipeline Company (or “CHOPS”), a 50% interest in Southeast Keathley Canyon Pipeline Company, LLC (or “SEKCO”), a 28% interest in Poseidon Oil Pipeline Company, L.L.C. (or "Poseidon") 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 Notes 3

and 8.

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 the expected life of the rights, expected forfeiture rates of the rights,

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volatility of our unit price 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 or market. Cost is determined principally under the average cost method within specific inventory pools.

Fixed Assets

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, 10 to 20 years for machinery and equipment, 3 to 7 years for transportation equipment, and 3 to 10 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.

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.

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 future asset retirement obligations relate to future costs associated with the removal of our oil and 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 6.

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 pipeline transportation services 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 7.

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CO_2 Assets
Our CO_2 assets include three volumetric production payments, which are amortized on a units-of-production method. These assets are included in Other Assets in our Consolidated Balance Sheets. See Note 9.
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 the issuance of long-term debt and certain amendments to our credit facilities are 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.
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 evaluation, we 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. If the calculated fair value of the reporting unit exceeds its book 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 book value including associated goodwill amounts, a charge to earnings may be necessary to reduce the carrying value of the goodwill to its implied fair value. In the event that we determine that goodwill has become impaired, we will incur a charge for the amount of impairment during the period in which the determination is made. No goodwill impairment has occurred in any of the periods presented. See Note 9 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 stock appreciation rights plan and 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 values of our equity-based awards are re-measured at the end of each reporting period and are recorded as liabilities. The liability and related compensation cost for our stock appreciation rights are calculated using a Black-Scholes option pricing model that takes into consideration the expected future value of the rights at their expected exercise dates and management's assumptions about expectation of forfeitures prior to vesting. The fair value of our phantom units is equal to the 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 15 for more information on these plans.
Revenue Recognition
Product Sales—Revenues from the sale of crude oil, petroleum products and CO_2 by our supply and logistics segment, and caustic soda and NaHS by our refinery services segment are recognized when title to the inventory is transferred

to the customer, pricing is fixed and determinable, collectibility is reasonably assured and there are no further significant obligations for future performance by us. Most frequently, title transfers upon our delivery of the inventory to the customer at a location designated by the customer, although in certain situations, title transfers when the inventory is loaded for transportation to the customer. Our crude oil and petroleum products are typically sold at prices based off daily or monthly published prices. Many of our contracts for sales of NaHS incorporate the price of caustic soda in the pricing formulas.

Marine Transportation—Revenues from the inland and offshore marine transportation of heavy refined petroleum products, including asphalt and crude oil, via our barges or vessels are recognized over the transit time of individual shipments as determined on an individual contract basis. Revenue from these contracts is typically based on a set day rate or a set fee per

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cargo movement. The costs of fuel, substantially all of which is a pass through expense, and other specified operational costs are directly reimbursed by the customer under most of these contracts.

Rail Facility Loading and Unloading Revenues—Revenues based on a per barrel fee from the loading and/or unloading of crude oil at our rail facilities is recognized as the crude oil enters or exits the railcars.

Pipeline Transportation—Revenues from transportation of crude oil by our pipelines are based on actual volumes at a published tariff. Tariff revenues are recognized either at the point of delivery or at the point of receipt pursuant to the specifications outlined in our regulated tariffs.

In order to compensate us for bearing the risk of volumetric losses in volumes that occur to crude oil in our pipelines due to temperature, crude quality and the inherent difficulties of measurement of liquids in a pipeline, our tariffs include the right for us to make volumetric deductions from the shippers for quality and volumetric fluctuations. We refer to these deductions as pipeline loss allowances.

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, based on prevailing market prices at that time. 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 that we must make to replace the lost volumes. We reflect inventories in the Consolidated Financial Statements at the lower of the recorded value or the market value at the balance sheet date. We value liabilities to replace crude oil at current market prices. The crude oil in inventory can then be sold, resulting in additional revenue if the sales price exceeds the inventory value.

Income from direct financing leases is being recognized ratably over the term of the leases and is included in pipeline revenues.

Cost of Sales and Operating Expenses

Supply and logistics costs and expenses include the cost to acquire the product and the associated costs to transport it to our terminal facilities 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 and barges, including personnel costs, fuel and maintenance of our equipment.

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 supply and logistics 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 rebillable and passed through to the customer.

The most significant operating costs in our refinery services segment consist of the costs to operate NaHS plants located at various refineries, caustic soda used in the process of processing the refiner’s sour gas stream, and costs to transport the NaHS and caustic soda.

Pipeline operating costs consist primarily of power costs to operate pumping equipment, personnel costs to operate the pipelines, insurance costs and costs associated with maintaining the integrity of our pipelines.

Excise and Sales Taxes

We collect and remit excise and sales taxes to state and federal governmental authorities on its sales of fuels. These taxes are presented on a net basis, with any differences due to rebates allowed by those governmental entities reflected as a reduction of product cost in the Consolidated Statements of Operations.

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

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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. See Note 17.

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.

Net Income Per Common Unit

Basic and diluted net income per common unit is determined by dividing net income attributable to limited partners by the weighted average number of outstanding common units during the period.

Prior Period Reclassifications

Certain prior period amounts have been reclassified to conform to the current period presentation, including our expanded presentation of "Revenues" and "Costs and Expenses" on our Consolidated Statements of Operations and expanded presentation in Note 12 relating to our change in segment reporting as previously discussed in Note 1.

Recent and Proposed Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board ("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 will be effective for us beginning January 1, 2017 and early adoption is not permitted. The guidance permits the use of either a full retrospective or a modified retrospective approach. We are evaluating the transition methods and the impact of the amended guidance on our financial position, results of operations and related disclosures.

3. Acquisitions and Divestitures

Acquisitions

M/T American Phoenix

On November 13, 2014, we acquired the M/T American Phoenix from Mid Ocean Tanker Company for $157 million. The M/T American Phoenix is a modern double-hulled, Jones Act qualified tanker with 330,000 barrels of cargo capacity that was placed into service during 2012.

The purchase price of $157 million was paid to Mid Ocean Tanker Company in cash, as funded with proceeds from available and committed liquidity under our $1 billion revolving credit facility. We have reflected the financial results of the acquired business in our marine transportation segment from the date of acquisition. We have recorded the assets acquired in the Consolidated Financial Statements at their fair values. Those fair values were developed by management.

The allocation of the purchase price, as presented on our Consolidated Balance Sheet, is summarized as follows:

Property and equipment	$125,000
Intangible assets	32,000
Total purchase price	$157,000

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Our Consolidated Financial Statements include the results of our acquired offshore marine transportation business since November 13, 2014, the effective 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, 2014
Revenues	$3,038
Net income	$454

The table below presents selected unaudited pro forma financial information for us incorporating the historical results of the acquired M/T American Phoenix. The pro forma financial information below has been prepared as if the acquisition had been completed on January 1, 2013 and is based upon assumptions deemed appropriate by us and may not be indicative of actual results. Depreciation expense for the fixed assets acquired is calculated on a straight-line basis over an estimated useful life of approximately 30 years.

	Year Ended December 31,	
	2014	2013
Pro forma earnings data:		
Revenues from continuing operations	$3,863,745	$4,153,443
Net Income	$111,132	$90,829

Offshore Marine Transportation Business

In August 2013, we acquired substantially all of the assets of the downstream transportation business of Hornbeck Offshore Services, Inc. for $230.9 million, which we refer to as our offshore marine transportation business and assets. The total acquisition cost of $230.9 million was allocated to fixed assets on our Consolidated Balance Sheet. The acquired business was primarily comprised of nine barges and nine tug boats that transport crude oil and refined petroleum products, principally serving refineries and storage terminals along the Gulf Coast, Eastern Seaboard, Great Lakes and Caribbean. That acquisition was funded with proceeds from our $1 billion revolving credit facility. We have reflected the financial results of the acquired business in our marine segment from the date of the acquisition.

Our Consolidated Financial Statements include the results of our acquired offshore marine transportation business since August 28, 2013, the effective closing date of that acquisition. The following table presents selected financial information included in our Consolidated Financial Statements for the periods presented:

	Year Ended December 31, 2013
Revenues	$30,424
Net income	$7,348

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The table below presents selected unaudited pro forma financial information for us incorporating the historical results of our offshore marine transportation business. The pro forma financial information below has been prepared as if the acquisition had been completed on January 1, 2012 and is based upon assumptions deemed appropriate by us and may not be indicative of actual results. Depreciation expense for the fixed assets acquired is calculated on a straight-line basis over an estimated useful life of approximately 25 years.

	Year Ended December 31, 2013	2012
Pro forma earnings data:		
Revenues from continuing operations	$4,177,715	$3,416,790
Net Income	$98,846	$98,665

Interests in Gulf of Mexico Crude Oil Pipeline Systems

On January 3, 2012, we acquired from Marathon Oil Company interests in several Gulf of Mexico crude oil pipeline systems. The acquired pipeline interests include a 28% interest in Poseidon Oil Pipeline Company, L.L.C., a 100% interest in Marathon Offshore Pipeline, LLC (subsequently re-named GEL Offshore Pipeline, LLC, or "GOPL") and a 29% interest in Odyssey Pipeline L.L.C. GOPL owns a 23% interest in the Eugene Island crude oil pipeline system and a 100% interest in two smaller offshore pipelines. The purchase price, net of post-closing adjustments, was $205.6 million. We funded the purchase price with cash available under our credit facility. We account for our interests in Poseidon and Odyssey under the equity method of accounting. We have recorded the assets acquired and liabilities assumed of GOPL in the Consolidated Financial Statements at their estimated fair values. Such fair values were developed by management.

Our Consolidated Financial Statements include the results of the acquired pipeline interests since the effective closing date of the acquisition in January 2012. The following table presents selected financial information included in our Consolidated Financial Statements for the year ended December 31, 2012:

	Year Ended December 31, 2012
Revenues	$5,508
Equity in earnings of equity investees	$13,118
Net income	$15,112

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Divestitures

On December 31, 2013 we sold our vehicle fuel procurement and delivery logistics management services business. We sold the business for $1 million and recorded a gain on the sale of approximately $0.9 million, included in Income (loss) from discontinued operations on the Consolidated Statements of Operations. That business, previously reported in our supply and logistics revenues and costs and expenses, was reclassified as discontinued operations in our Consolidated Statements of Operations for the years ended December 31, 2013 and 2012. The summarized operating results of our discontinued operations are as follows:

	Year Ended December 31, 2013	2012
Revenues	$593,733	$702,695
Cost and expenses	592,505	703,715
Operating income (loss)	1,228	(1,020)
Interest income	2	2
Income (loss) before income taxes	1,230	(1,018)
Gain on sale of discontinued operations	875	—
Income (loss) from discontinued operations	$2,105	$(1,018)

4. Receivables

Accounts receivable – trade, net consisted of the following:

	December 31, 2014	2013
Accounts receivable - trade	$274,502	$369,559
Allowance for doubtful accounts	(2,973)	(1,526)
Accounts receivable - trade, net	$271,529	$368,033

The following table presents the activity of our allowance for doubtful accounts for the periods indicated:

	December 31, 2014	2013	2012
Balance at beginning of period	$1,526	$2,372	$1,044
(Credited) charged to costs and expenses	1,447	(86)	2,096
Amounts written off	—	(760)	(768)
Balance at end of period	$2,973	$1,526	$2,372

5. Inventories

The major components of inventories were as follows:

	December 31, 2014	2013
Petroleum products	$30,108	$71,373
Crude oil	7,266	5,380
Caustic soda	2,850	2,679
NaHS	6,603	5,845
Other	2	53
Total	$46,829	$85,330

Inventories are valued at the lower of cost or market. The market value of inventories was below recorded costs by approximately $6.6 million at December 31, 2014; therefore we reduced the value of inventory in our Condensed Consolidated Financial Statements for this difference. At December 31, 2013, market values of our inventory exceeded recorded costs.

6. Fixed Assets and Asset Retirement Obligations

Fixed Assets

Fixed assets consisted of the following:

	December 31,	
	2014	2013
Pipelines and related assets	$466,613	$338,920
Machinery and equipment	376,672	173,092
Transportation equipment	18,479	19,140
Marine vessels	731,016	554,679
Land, buildings and improvements	38,037	30,170
Office equipment, furniture and fixtures	6,696	5,633
Construction in progress	222,233	183,037
Other	39,312	23,303
Fixed assets, at cost	1,899,058	1,327,974
Less: Accumulated depreciation	(268,057)	(199,230)
Net fixed assets	$1,631,001	$1,128,744

Depreciation expense was $73.2 million, $46.3 million and $37.4 million for the years ended December 31, 2014, 2013, and 2012, respectively.

Asset Retirement Obligations

A reconciliation of our liability for asset retirement obligations is as follows:

December 31, 2012	$12,695
Liabilities incurred	789
Accretion expense	848
December 31, 2013	14,332
Liabilities incurred	—
Accretion expense	458
December 31, 2014	$14,790

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7. 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. The following table lists the components of the net investment in direct financing leases:

	December 31,	
	2014	2013
Total minimum lease payments to be received	$277,732	$298,924
Estimated residual values of leased property (unguaranteed)	292	292
Unamortized initial direct costs	1,444	1,621
Less unearned income	(127,531)	(143,415)
Net investment in direct financing leases	151,937	157,422
Less current portion (included in other current assets)	(5,978)	(5,519)
Long-term portion of net investment in direct financing leases	$145,959	$151,903

At December 31, 2014, minimum lease payments to be received for each of the five succeeding fiscal years are $20.7 million.

8. 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 the underlying book value of the capital accounts we acquire. Such excess cost amounts are included within the carrying values of our equity investees. At December 31, 2014 and 2013, the unamortized excess cost amounts totaled $215.4 million and $225.7 million, respectively. We amortize the excess cost as a reduction in equity earnings in a manner similar to depreciation.

The following table presents information included in our Consolidated Financial Statements related to our equity investees.

	Year Ended December 31,		
	2014	2013	2012
Genesis' share of operating earnings	$53,783	$33,152	$24,532
Amortization of excess purchase price	(10,648)	(10,477)	(10,187)
Net equity in earnings	$43,135	$22,675	$14,345
Distributions received	$75,528	$46,564	$38,809

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):

	December 31,	
	2014	2013
BALANCE SHEET DATA:		
Assets		
Current assets	$42,135	$70,921
Fixed assets, net	1,015,305	1,028,808
Other assets	4,369	6,823
Total assets	$1,061,809	$1,106,552
Liabilities and equity		
Current liabilities	$25,369	$55,918

Other liabilities	202,613	190,578
Equity	833,827	860,056
Total liabilities and equity	$1,061,809	$1,106,552

	Year Ended December 31,		
	2014	2013	2012
INCOME STATEMENT DATA:			
Revenues	$246,265	$183,533	$162,267
Operating Income	$146,760	$102,107	$80,841
Net Income	$142,754	$99,357	$77,975

9. Intangible Assets, Goodwill and Other Assets

Intangible Assets

The following table reflects the components of intangible assets being amortized at December 31, 2014 and 2013:

		December 31, 2014			December 31, 2013		
	Weighted Amortization Period in Years	Gross Carrying Amount	Accumulated Amortization	Carrying Value	Gross Carrying Amount	Accumulated Amortization	Carrying Value
Refinery Services:							
Customer relationships	5	$94,654	$ 81,880	$12,774	$94,654	$ 76,283	$18,371
Licensing agreements	6	38,678	28,983	9,695	38,678	26,055	12,623
Segment total		133,332	110,863	22,469	133,332	102,338	30,994
Supply & Logistics:							
Customer relationships	5	35,430	30,228	5,202	35,430	28,568	6,862
Intangibles associated with lease	15	13,260	3,512	9,748	13,260	3,039	10,221
Segment total		48,690	33,740	14,950	48,690	31,607	17,083
Marine contract intangibles	5	32,000	833	31,167	—	—	—
Other	5	22,797	8,452	14,345	21,356	6,505	14,851
Total		$236,819	$ 153,888	$82,931	$203,378	$ 140,450	$62,928

The licensing agreements referred to in the table above relate to the agreements we have with refiners to provide services. The supply and logistics lease relates to a terminal facility in Shreveport, Louisiana. The marine contract intangibles relate to the contracts we assumed in the purchase of the M/T American Phoenix in November 2014.

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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 supply and logistics lease, marine contract, and other intangible assets are being amortized on a straight-line basis. Amortization expense on intangible assets was $13.4 million, $14.6 million and $19.9 million for the years ended December 31, 2014, 2013 and 2012, respectively.

The following table reflects our estimated amortization expense for each of the five subsequent fiscal years:

	2015	2016	2017	2018	2019
Refinery Services:					
Customer relationships	$4,405	$3,471	$2,737	$2,161	$—
Licensing agreements	2,711	2,510	2,324	2,150	—
Supply and Logistics:					
Customer relationships	1,275	981	757	586	454
Intangibles associated with lease	474	474	474	474	474
Marine contract intangibles	6,417	5,400	5,400	5,400	5,400
Other	2,057	2,025	2,006	2,006	2,006
Total	$17,339	$14,861	$13,698	$12,777	$8,334

Goodwill

The carrying amount of goodwill by business segment at both December 31, 2014 and 2013 was $301.9 million in refinery services and $23.1 million in supply and logistics. We have not recognized any impairment losses related to goodwill for any of the periods presented.

Other Assets

Other assets consisted of the following:

	December 31,	
	2014	2013
CO_2 volumetric production payments, net of amortization	$9,395	$4,421
Deferred marine charges [1]	13,042	2,829
Other deferred costs and deposits	38,854	30,861
Other assets, net of amortization	$61,291	$38,111

(1) See discussion of deferred charges on marine transportation assets in the Summary of Accounting Policies (Note 2)

The CO_2 assets are being amortized on a units-of-production method. We recorded amortization of $4.2 million in 2014, $3.9 million in 2013 and $3.8 million in 2012.

10. Debt

At December 31, 2014 and 2013, our obligations under debt arrangements consisted of the following:

	December 31,	
	2014	2013
Senior secured credit facility	$550,400	$582,800
7.875% senior unsecured notes (including unamortized premium of $639 and $772 in 2014 and 2013, respectively)	350,639	350,772
5.750% senior unsecured notes	$350,000	350,000
5.625% senior unsecured notes	$350,000	—
Total long-term debt	$1,601,039	$1,283,572

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Senior Secured Credit Facility

In June 2014, we amended and restated our $1 billion senior secured credit facility with a syndicate of banks to, among other things, extend the term of our credit facility to July 25, 2019. Additionally, the accordion feature was increased from $300 million to $500 million, giving us the ability to expand the size of the facility up to an aggregate $1.5 billion for acquisitions or internal growth projects, subject to lender consent. Our credit facility includes an inventory financing sublimit of $150 million.

The key terms for rates under our 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 2.50% on Eurodollar borrowings and from 0.50% to 1.50% 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, 2014, the applicable margins on our borrowings were 1.25% for alternate base rate borrowings and 2.25% for Eurodollar rate borrowings.
- Letter of credit fees range from 1.50% to 2.50% based on our leverage ratio as computed under the credit facility. The rate can fluctuate quarterly. At December 31, 2014, our letter of credit rate was 2.25%.
- We pay a commitment fee on the unused portion of the $1 billion maximum facility amount. The commitment fee on the unused committed amount will range from 0.250% to 0.375% per annum depending on our leverage ratio (0.375% at December 31, 2014).

Our credit facility is secured by liens on a substantial portion of our assets, and by guarantees by all of our restricted subsidiaries (as defined in the credit facility).

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 5.00 to 1.00 (5.50 to 1.00 in an acquisition period). Our senior secured leverage ratio excludes outstanding debt under senior unsecured notes and cannot exceed 3.75 to 1.00 (4.25 to 1.00 in an acquisition period). 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, 2014, we had $550.4 million borrowed under our credit facility, with $45.0 million of the borrowed amount designated as a loan under the inventory sublimit. The credit agreement allows up to $100 million of the capacity to be used for letters of credit, of which $10.8 million was outstanding at December 31, 2014. 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 July 25, 2019. The total amount available for borrowings under our credit facility at December 31, 2014 was $438.8 million.

Senior Unsecured Notes

In November 2010, we issued $250 million in aggregate principal amount of 7.875% senior unsecured notes due December 15, 2018 (the "2018 Notes"). The 2018 Notes were sold at face value. Interest payments are due on June 15 and December 15 of each year. In February 2012, we issued an additional $100 million of aggregate principal amount of additional 2018 Notes. The additional 2018 Notes were issued at 101% of face value at an effective interest rate of 7.682%. The additional 2018 Notes have the same terms and conditions as the notes previously issued under the indenture. The issuance increased the total aggregate principal amount of the 2018 Notes to $350 million.

On February 8, 2013, we issued $350 million of aggregate principal amount of 5.75% senior unsecured notes (the "2021 Notes"). The 2021 Notes were sold at face value. Interest payments are due on February 15 and August 15 of each year. The 2021 Notes mature on February 15, 2021. The net proceeds were used to repay borrowings under our credit facility and for general partnership purposes.

On May 15, 2014, we issued $350 million in aggregate principal amount of 5.625% senior unsecured notes (the "2024 Notes"). The 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. The 2024 Notes mature on June 15, 2024.

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The 2018, 2021 and 2024 Notes were co-issued by Genesis Energy Finance Corporation (which has no independent assets or operations) and are each fully and unconditionally guaranteed, subject to customary exceptions pursuant to the indentures governing our 2018, 2021 and 2024 Notes, as discussed below, jointly and severally, by certain of our wholly-owned subsidiaries. We have the right to redeem the 2018 Notes at any time after December 15, 2014, at a premium to the face amount of the notes that varies based on the time remaining to maturity of the 2018 Notes. We have the right to redeem the 2021 Notes at any time after February 15, 2017, at a premium to the face amount of the 2021 Notes that varies based on the time remaining to maturity on the 2021 Notes. Prior to February 15, 2016, we may also redeem up to 35% of the principal amount of the 2021 Notes for 105.75% of the face amount with the proceeds from an equity offering of our common units. We have the right to redeem the 2024 Notes at any time after June 15, 2019, at a premium to the face amount of the 2024 Notes that varies based on the time remaining to maturity on the 2024 Notes. Prior to June 15, 2017, we may also redeem up to 35% of the principal amount of the 2024 Notes for 105.625% of the face amount with the proceeds from an equity offering of our common units.

Guarantees of the 2018, 2021 and 2024 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, 2014, we were in compliance with the financial covenants contained in our credit facility and indenture.

11. Partners’ Capital and Distributions

At December 31, 2014, our outstanding equity consisted of 94,989,221 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.

Our outstanding equity also included non-voting securities -- waiver units -- that were entitled to a minimal quarterly distribution until conversion into Class A common units at a 1 to 1 ratio. As of December 31, 2014, all of our waiver units had been converted into common units.

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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 consists generally of all of our cash receipts less cash disbursements adjusted for net changes to reserves. We paid distributions in 2015, 2014 and 2013 as follows:

Distribution For	Date Paid	Per Unit Amount	Total Amount
2012			
4th Quarter	February 14, 2013	$0.4850	$39,390
2013			
1st Quarter	May 15, 2013	$0.4975	$40,405
2nd Quarter	August 14, 2013	$0.5100	$42,302
3rd Quarter	November 14, 2013	$0.5225	$46,344
4th Quarter	February 14, 2014	$0.5350	$47,453
2014			
1st Quarter	May 15, 2014	$0.5500	$48,783
2nd Quarter	August 14, 2014	$0.5650	$50,114
3rd Quarter	November 14, 2014	$0.5800	$54,112
4th Quarter	February 13, 2015	$0.5950	$56,542

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.

In September 2014, we issued 4,600,000 Class A common units in a public offering at a price of $50.71 per unit. We received proceeds, net of underwriting discounts and offering costs, of approximately $225.7 million from that offering. We used the net proceeds for general partnership purposes, including the repayment of outstanding borrowings under our revolving credit facility.

In September 2013, we issued 5,750,000 Class A common units in a public offering at a price of $47.51 per unit. We received proceeds, net of underwriting discounts and offering costs, of approximately $263.6 million from that offering. We used the net proceeds for general partnership purposes, including the repayment of outstanding borrowings under our revolving credit facility.

In March 2012, we issued 5,750,000 Class A common units in a public offering at a price of $30.80 per unit. We received proceeds, net of underwriting discounts and offering costs, of $169.4 million from the offering. The net proceeds were used for general corporate purposes, including the repayment of borrowings under our credit facility.

The new common units issued in 2014, 2013 and 2012 to the public for cash were as follows:

Period	Purchaser of Common Units	Units	Gross Unit Price	Issuance Value	Costs	Net Proceeds
September 2014	Public	4,600	$50.71	$233,266	$(7,541)	$225,725
September 2013	Public	5,750	$47.51	$273,183	$(9,609)	$263,574
March 2012	Public	5,750	$30.80	$177,100	$(7,679)	$169,421

12. Business Segment Information

Our operations consist of five operating segments (see Note 1 for discussion of segment reporting change):

- Onshore Pipeline Transportation – transportation of crude oil, and to a lesser extent, CO_2;

- Offshore Pipeline Transportation – offshore transportation of crude oil in the Gulf of Mexico;

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- Refinery Services – processing high sulfur (or "sour") gas streams as part of refining operations to remove the sulfur and selling the related by-product, NaHS;
- Marine Transportation – marine transportation to provide waterborne transportation of petroleum products and crude oil throughout North America and;
- Supply and Logistics – terminaling, blending, storing, marketing, and transporting crude oil and petroleum products (primarily fuel oil, asphalt, and other heavy refined products) and, on a smaller scale, CO_2.

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.

Segment information for each year presented below is as follows:

	Onshore Pipeline Transportation	Offshore Pipeline Transportation	Refinery Services	Marine Transportation	Supply & Logistics[a]	Total
Year Ended December 31, 2014						
Segment Margin [b]	$61,231	$71,598	$84,851	$ 86,239	$43,345	$347,264
Capital expenditures [c]	$46,611	$37,639	$2,385	$ 232,783	$325,130	$644,548
Revenues:						
External customers	$66,760	$3,296	$218,297	$ 214,039	$3,343,772	$3,846,164
Intersegment [d]	16,397	—	(10,896)	15,243	(20,744)	—
Total revenues of reportable segments	$83,157	$3,296	$207,401	$ 229,282	$3,323,028	$3,846,164
Year Ended December 31, 2013						
Segment Margin [b]	$64,349	$44,530	$75,361	$ 47,726	$48,394	$280,360
Capital expenditures [c]	$130,787	$94,286	$3,258	$ 260,736	$215,138	$704,205
Revenues:						
External customers	$65,452	$3,923	$216,860	$ 131,049	$3,717,546	$4,134,830
Intersegment [d]	17,133	—	(10,875)	21,493	(27,751)	—
Total revenues of reportable segments	$82,585	$3,923	$205,985	$ 152,542	$3,689,795	$4,134,830
Year Ended December 31, 2012						
Segment Margin [b]	$58,039	$38,500	$72,883	$ 37,528	$55,383	$262,333
Capital expenditures [c]	$59,345	$269,365	$2,692	$ 37,188	$57,708	$426,298
Revenues:						
External customers	$56,198	$5,508	$205,110	$ 99,016	$3,001,529	$3,367,361
Intersegment [d]	14,584	—	(9,093)	19,188	(24,679)	—
Total revenues of reportable segments	$70,782	$5,508	$196,017	$ 118,204	$2,976,850	$3,367,361

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Total assets by reportable segment were as follows:

	December 31, 2014	December 31, 2013	December 31, 2012
Onshore pipeline transportation	$ 460,012	$ 437,912	$ 325,189
Offshore pipeline transportation	645,668	637,323	565,463
Refinery services	403,703	417,121	414,170
Marine transportation	745,128	529,914	276,736
Supply and logistics	907,189	782,547	473,611
Other assets	68,674	57,385	54,495
Total consolidated assets	$ 3,230,374	$ 2,862,202	$ 2,109,664

(a) Discontinued operations are included in Segment Margin but excluded from revenues for all periods presented.

(b) A reconciliation of Segment Margin to income from continuing operations before income taxes for each year is presented below.

(c) Capital expenditures include maintenance and growth capital expenditures, such as fixed asset additions (including enhancements to existing facilities and construction of internal growth projects) as well as acquisitions of businesses and interests in equity investees. In addition to construction of internal growth projects, capital spending in our Offshore pipeline transportation segment included $36.1 million and $94.3 million during the years ended December 31, 2014 and December 31, 2013 representing capital contributions to our SEKCO equity investee to fund our share of the construction costs for its pipeline. During 2014, capital spending in our marine transportation segment included $157 million for our purchase of the M/T American Phoenix. During 2013, capital spending in our marine segment also included $230.9 million for the acquisition of our offshore marine transportation assets. During 2012, capital spending in our pipeline transportation segment also included $205.6 million for the acquisition of interests in several Gulf of Mexico pipelines.

(d) Intersegment sales were conducted under terms that we believe were no more or less favorable than then-existing market conditions.

Reconciliation of Segment Margin to income from continuing operations:

	Year Ended December 31, 2014	2013	2012
Segment Margin	$347,264	$280,360	$262,333
Corporate general and administrative expenses	(47,065)	(43,353)	(38,372)
Depreciation and amortization	(90,908)	(64,784)	(61,150)
Interest expense	(66,639)	(48,583)	(40,923)
Adjustment to exclude distributable cash generated by equity investees not included in income and include equity in investees net income (1)	(31,093)	(23,889)	(24,464)
Non-cash items not included in Segment Margin	3,017	(7,551)	(5,280)
Cash payments from direct financing leases in excess of earnings	(5,529)	(5,110)	(5,016)
Income tax expense	(2,845)	(845)	9,205
Discontinued operations	—	(2,241)	1,004
Income from continuing operations	$106,202	$84,004	$97,337

(1) Includes distributions attributable to the quarter and received during or promptly following such quarter.

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13. Transactions with Related Parties

Sales, purchases and other transactions with affiliated companies, in the opinion of management, are conducted under terms no more or less favorable than then-existing market conditions. The transactions with related parties were as follows:

	Year Ended December 31,		
	2014	2013	2012
Revenues:			
Sales of CO_2 to Sandhill Group, LLC (1)	$3,060	$3,076	$2,905
Petroleum products sales to Davison family businesses(2)	—	1,293	1,344
Petroleum products sales to an affiliate of the Quintana Group (2) (3)	—	—	21,143
Expenses:			
Amounts paid to our CEO in connection with the use of his aircraft	$630	$600	$600
Marine operating fuel and expenses provided by an affiliate of the Quintana Group (3)	—	—	6,260

(1) We own a 50% interest in Sandhill Group, LLC (or "Sandhill).

(2) Amounts included in discontinued operations for all periods presented.

The Quintana Group monetized all of its remaining investment in our common units on October 5, 2012.

(3) Transactions with the Quintana Group are included in the above table as related party transactions through October 5, 2012.

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.

Amounts due from Related Parties

At December 31, 2014, and 2013, Sandhill owed us $0.3 million and $0.2 million, respectively, for purchases of CO_2.

14. Supplemental Cash Flow Information

The following table provides information regarding the net changes in components of operating assets and liabilities:

	Year Ended December 31,		
	2014	2013	2012
(Increase) decrease in:			
Accounts receivable	$95,014	$(96,300)	$(34,299)
Inventories	38,501	1,720	14,074
Deferred Charges	(8,935)	—	—
Other current assets	62,305	(39,170)	(9,593)
Increase (decrease) in:			
Accounts payable	(73,307)	41,718	53,146
Accrued liabilities	(35,624)	45,846	(10,263)
Net changes in components of operating assets and liabilities	$77,954	$(46,186)	$13,065

Payments of interest and commitment fees, net of amounts capitalized, were $74.8 million, $49.7 million and $41.5 million during the years ended December 31, 2014, 2013 and 2012, respectively. We capitalized interest of $13.8 million, $13.3 million and $3.9 million during the years ended December 31, 2014, 2013 and 2012.

During the years ended December 31, 2014 and 2013, we paid taxes of $0.8 million and $0.6 million. During the year ended December 31, 2012, we received a tax refund, net of amounts paid, of $0.3 million.

At December 31, 2014, 2013 and 2012, we had incurred liabilities for fixed and intangible asset additions totaling $61.2 million, $52.5 million and $14.1 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.

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At December 31, 2014 and 2013, we had incurred liabilities for other asset additions totaling $9.4 million and $0.1 million that had not been paid at the end of the year, and, therefore, were not included in the caption "Other, net" under Cash Flows from Investing Activities in the Consolidated Statements of Cash Flows.

15. Equity-Based Compensation Plans and Employee Benefit 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 LTIP is adjusted to recognize changes in the estimated compensation cost and vesting. Management’s estimates of the fair value of these awards granted in 2014 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 2014, we granted 125,988 phantom units with tandem DERs at a weighted average grant fair value of $54.14 per unit. During 2013, we granted 152,964 phantom units with tandem DERs at a weighted average grant date fair value of $46.88 per unit. The phantom units granted during 2014 and 2013 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 2013 and 2014 will vest on the third anniversary of issuance, in an amount ranging from 50% 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 2015 and 2016, 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.

During 2012, we granted 176,995 phantom units with tandem DERs at a weighted average grant date fair value of $31.14 per unit. These phantom units will vest in April 2015, the third anniversary of the date of grant, at 150% of the targeted number of phantom units due to the distribution per common unit target achieved in the fourth quarter of 2014.

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, 2013	105,385	$35.42	$3,733	334,969	$35.79	$11,989
Granted	43,225	$54.05	2,336	82,763	$54.18	4,484
Forfeited	(4,599)	$43.19	(199)	(6,899)	$43.20	(298)
Settled	(31,188)	$27.11	(846)	(96,988)	$28.21	(2,736)
Unvested at December 31, 2014	112,823	$44.53	$5,024	313,845	$42.82	$13,439

At December 31, 2014, we estimated the unrecognized compensation cost of our phantom awards to be approximately $4.9 million to be recognized over a weighted average period of approximately one year. We recorded $8.8 million and $13.1 million of compensation expense for the years ended December 31, 2014 and 2013, respectively. Our liability for these awards totaled $15.4 million and $17.1 million at December 31, 2014 and 2013, respectively.

Stock Appreciation Rights Plan

Our Stock Appreciation Rights Plan is administered by the G&C Committee, which determines, in its full discretion, who shall receive awards under the Plan, the number of rights to award, the grant date of the units and the formula for allocating rights to the participants and the strike price of the rights awarded. Each right is equivalent to one common unit.

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The rights have a term of 10 years from the date of grant. If the right has not been exercised at the end of the ten year term and the participant has not terminated employment with us, the right will be deemed exercised as of the date of the right's expiration and a cash payment will be made as described below.

Upon vesting, the participant may exercise rights and receive a cash payment calculated as the difference between the average of the closing market price of our common units for the ten days preceding the date of exercise over the strike price of the right being exercised. If the G&C Committee determines, in its full discretion, that it would cause significant financial harm to the Partnership to make cash payments to participants who have exercised rights under the Stock Appreciation Rights Plan, then the G&C Committee may authorize deferral of the cash payments until a later date.

Termination for any reason other than death, disability or normal retirement (as these terms are defined in the Stock Appreciation Rights Plan) will result in the forfeiture of any non-vested rights. Upon death, disability or normal retirement, all rights will become fully vested. If a participant is terminated for any reason within one year after the effective date of a change in control (as defined in the plan) all rights will become fully vested.

The compensation cost associated with our Stock Appreciation Rights plan, which upon exercise will result in the payment of cash to the employee, is re-measured each reporting period based on the fair value of the rights calculated using a Black-Scholes option pricing model that takes into consideration the expected future value of the rights at their expected exercise dates and management's assumptions about expectation of forfeitures prior to vesting.

The liability amount accrued on the balance sheet is adjusted to the fair value of the outstanding awards at each balance sheet date with the adjustment reflected in the Consolidated Statement of Operations. The fair value is adjusted for expected forfeitures of rights (due to terminations before vesting, or expirations after vesting).

The estimates that we make each period to determine the fair value of these rights include the following assumptions:

	Assumptions Used for Fair Value of Rights					
	December 31, 2014		December 31, 2013		December 31, 2012	
Expected life of rights (in years)	Less than 1		Less than 1		Less than 1	
Risk-free interest rate	—%	- 0.07%	—%	- 0.07%	—%	- 0.07%
Expected unit price volatility	39.3%		39.3%		39.3%	
Expected future distribution yield	5.00%		5.00%		5.00%	

The following table reflects rights activity under our Stock Appreciation Rights Plan as of January 1, 2014, and changes during the year ended December 31, 2014:

	Stock Appreciation Rights		Weighted Average Strike Price	Weighted Average Contractual Remaining Term (Yrs)	Aggregate Intrinsic Value
Outstanding at December 31, 2013	207,498		$17.43		
Exercised during 2014	(37,813	)	$51.59		
Forfeited or expired during 2014	(8,830	)	$16.03		
Outstanding at December 31, 2014	160,855		$18.08	3.47	$3,906
Exercisable at December 31, 2014	160,855		$18.08	3.47	$3,906

The total intrinsic value of rights exercised during 2014, 2013 and 2012 was $1.4 million, $5.5 million and $3.3 million, respectively, which was paid in cash to the participants.

As of December 31, 2014, all of our SARs were vested and the related total compensation cost had been fully recognized.

We recorded a reduction to compensation expense related to our stock appreciation rights from continuing operations of $2.0 million in 2014. In 2013 and 2012 we recorded compensation expense related to our stock appreciation rights from continuing operations of $5.6 million and $4.3 million, respectively.

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Equity-Based Compensation Plan Expense

Equity-based compensation expense from our continuing operations during the three years ended December 31, 2014 was as follows:

	Expense Related to Equity-Based Compensation Plans		
Consolidated Statement of Operations	2014	2013	2012
Supply and logistics operating costs	$485	$4,524	$2,707
Marine transportation operating costs	626	586	190
Refinery services operating costs	(62)	1,978	1,427
Pipeline operating costs	(52)	510	247
General and administrative expenses	5,824	11,073	6,448
Total	$6,821	$18,671	$11,019

Bonus Program

Bonuses under our bonus plan are paid at the discretion of the G&C Committee to our employees and executive officers based on quantitative and qualitative measures relating to: our financial and operational performance relative to our peers; industry expectations; progress in attaining strategic goals; and individual performance. In 2014, the G&C Committee based bonus amounts primarily on the amount of cash we generated for distributions to our unitholders, measured on a calendar-year basis. Two metrics were considered by the G&C Committee in determining the general bonus pool – the level of Available Cash before Reserves (before subtracting bonus expense and related employer tax burdens) that we generated and our company-wide safety record improvement which included a targeted achieved level in our company-wide incident injury rate. The level of Available Cash before Reserves generated for the year as a percentage of a target set by the G&C Committee is weighted 90% and the achieved level of the targeted improvement in our safety record is weighted 10%. The sum of the weighted percentage achievement of these targets is multiplied by the eligible compensation and the target percentages established by the G&C Committee for the various levels of our employees to determine the maximum general bonus pool. In addition, the G&C Committee also considered other subjective factors in determining the general bonus pool and individual award amounts. At December 31, 2014, we accrued $8.1 million for estimated bonuses to be paid in March 2015. For 2013 and 2012, we paid bonuses totaling $5.3 million and $7.9 million, respectively, to our executive officers and employees.

Employee Benefit Plans

In order to encourage long-term savings and to provide additional funds for retirement to its employees, we sponsor a tax qualified profit-sharing and retirement savings plan. Under this plan, our matching contribution is calculated as an equal match of the first 6% of each employee’s annual pretax contribution. Our profit-sharing plan targets a 3% contribution of each eligible employee’s total compensation (subject to IRS limitations). The expenses included in the Consolidated Statements of Operations for costs relating to this plan were $6.3 million, $4.3 million and $3.4 million for the years ended December 31, 2014, 2013 and 2012, respectively.

We also provided certain health care and survivor benefits for our active employees. Our health care benefit programs are self-insured, with a catastrophic insurance policy to limit our costs. We plan to continue self-insuring these plans in the future. The expenses included in the Consolidated Statements of Operations for these benefits were $13.5 million, $10.4 million and $8.8 million in 2014, 2013 and 2012, respectively.

16. Major Customers and Credit Risk

Due to the nature of our supply and logistics operations, a disproportionate percentage of our trade receivables constitute obligations of 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.

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During 2014, 2013 and 2012 our largest customer was Shell Oil Company, which accounted for 12%, 17% and 14% of total revenues respectively. The revenues from Shell Oil Company in all three years relate primarily to our supply and logistics operations.

17. 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 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.

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.

At December 31, 2014, we had the following outstanding derivative commodity contracts that were entered into to economically hedge inventory or fixed price purchase commitments. We had no outstanding derivative contracts that were designated as hedges under accounting rules.

	Sell (Short) Contracts	Buy (Long) Contracts
Not qualifying or not designated as hedges under accounting rules:		
Crude oil futures:		
Contract volumes (1,000 bbls)	366	168
Weighted average contract price per bbl	$74.82	$65.30
Diesel futures:		
Contract volumes (1,000 bbls)	56	—
Weighted average contract price per gal	$2.43	$—
#6 Fuel oil futures:		
Contract volumes (1,000 bbls)	465	95
Weighted average contract price per bbl	$60.07	$44.95
Crude oil options:		
Contract volumes (1,000 bbls)	125	—
Weighted average premium received	$2.08	$—

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Financial Statement Impacts
The following table summarizes the accounting treatment and classification of our derivative instruments on our Consolidated Financial Statements.

Derivative Instrument	Hedged Risk	Impact of Unrealized Gains and Losses Consolidated Balance Sheets	 Consolidated Statements of Operations
Not qualifying or not designated as hedges under accounting guidance:			
Commodity hedges consisting of crude oil, heating oil and natural gas futures and forward contracts and call options	Volatility in crude oil 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 Supply and logistics costs - product costs

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.

The following tables reflect the estimated fair value gain (loss) position of our derivatives at December 31, 2014 and 2013:
Fair Value of Derivative Assets and Liabilities

	Consolidated Balance Sheets Location	Fair Value December 31, 2014	 December 31, 2013
Asset Derivatives:			
Commodity derivatives—futures and call options (undesignated hedges):			
Gross amount of recognized assets	Current Assets - Other	$16,383	$615
Gross amount offset in the Consolidated Balance Sheets	Current Assets - Other	(2,310)	(615)
Net amount of assets presented in the Consolidated Balance Sheets		14,073	—
Liability Derivatives:			
Commodity derivatives—futures and call options (undesignated hedges):			
Gross amount of recognized liabilities	Current Assets - Other [(1)]	$(2,310)	$(4,527)
Gross amount offset in the Consolidated Balance Sheets	Current Assets - Other [(1)]	2,310	4,527
Net amount of liabilities presented in the Consolidated Balance Sheets		—	—

(1) These derivative liabilities have been funded with margin deposits recorded in our Consolidated Balance Sheets under Current Assets - Other in 2013.

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, 2014, we had a net broker receivable of approximately $2.8 million (consisting of initial margin of $2.4 million increased by $0.3 million of variation margin). As of December 31, 2013, we had a net broker receivable of approximately $5.3 million (consisting of initial margin of $4.1 million increased by $1.2 million of variation margin that had

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been returned to us). At December 31, 2014 and December 31, 2013, 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.

Effect on Operating Results

	Amount of Gain (Loss) Recognized in Income Supply & Logistics Product Costs Year Ended December 31,		
	2014	2013	2012
Commodity derivatives—futures and call options:			
Contracts designated as hedges under accounting guidance	$—	$—	$—
Contracts not considered hedges under accounting guidance	35,468	(3,268)	(2,936)
Total derivatives	$35,468	$(3,268)	$(2,936)

We have no derivative contracts with credit contingent features.

18. 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.

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, 2014 and 2013.

	December 31, 2014			December 31, 2013		
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Commodity derivatives:						
Assets	$16,383	$—	$—	$615	$—	$—
Liabilities	$(2,310)	$—	$—	$(4,527)	$—	$—

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.

See Note 17 for additional information on our derivative instruments.

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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, 2014 our senior unsecured notes had a carrying value of $1,050.6 million and a fair value of $1,003.6 million, compared to $700.8 million and $732.4 million, respectively at December 31, 2013. 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.
19. 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, 2014, were as follows (in thousands):

	Office Space	Transportation Equipment	Terminals and Tanks	Total
2015	$2,282	$14,796	$15,752	$32,830
2016	1,846	9,451	7,149	18,446
2017	1,625	7,430	2,687	11,742
2018	1,631	5,967	2,692	10,290
2019	1,580	5,705	2,697	9,982
2020 and thereafter	4,484	6,617	20,866	31,967
Total minimum lease obligations	$13,448	$49,966	$51,843	$115,257

Total operating lease expense from our continuing operations was as follows (in thousands):

Year Ended December 31, 2014	$37,941
Year Ended December 31, 2013	$27,674
Year Ended December 31, 2012	$21,530

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.

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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.

20. 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.

Our income tax (benefit) expense is as follows:

	Year Ended December 31,		
	2014	2013	2012
Current:			
Federal	$—	$345	$(8,463)
State	1,100	650	275
Total current income tax expense (benefit)	$1,100	$995	$(8,188)
Deferred:			
Federal	$1,508	$(248)	$(1,035)
State	237	98	18
Total deferred income tax benefit	$1,745	$(150)	$(1,017)
Total income tax expense (benefit) from continuing operations (1)	$2,845	$845	$(9,205)

(1) Our discontinued operations had no income tax benefit or expense in any period presented.

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Deferred income taxes relate to temporary differences based on tax laws and statutory rates in effect at the balance sheet date. Deferred tax assets and liabilities consist of the following:

	December 31, 2014	2013
Deferred tax assets:		
Current:		
Other current assets	$262	$297
Other	8	8
Total current deferred tax asset	270	305
Net operating loss carryforwards	9,048	7,784
Total long-term deferred tax asset	9,048	7,784
Valuation allowances	(737)	(660)
Total deferred tax assets	$8,581	$7,429
Deferred tax liabilities:		
Current:		
Other	$(871)	$(785)
Long-term:		
Fixed assets	(4,335)	(4,441)
Intangible assets	(14,419)	(11,503)
Total long-term liability	(18,754)	(15,944)
Total deferred tax liabilities	$(19,625)	$(16,729)
Total net deferred tax liability	$(11,044)	$(9,300)

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.

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Our income tax expense (benefit) varies from the amount that would result from applying the federal statutory income tax rate to income from continuing operations before income taxes as follows:

	Year Ended December 31,		
	2014	2013	2012
Income from continuing operations before income taxes	$109,047	$84,849	$88,132
Partnership income not subject to tax	(104,751)	(85,567)	(90,815)
Income (loss) subject to income taxes	$4,296	$(718)	$(2,683)
Tax expense (benefit) at federal statutory rate	$1,504	$(251)	$(939)
State income taxes, net of federal tax	992	660	460
Effects of unrecognized tax positions, federal and state	—	—	(8,205)
Return to provision, federal and state	(232)	88	(166)
Other	581	348	(355)
Income tax expense (benefit)	$2,845	$845	$(9,205)
Effective tax rate on income from continuing operations before income taxes (1)	3%	1%	N/A

Income tax expense is related to taxable income generated by our corporate subsidiaries and Texas Margin Tax.

(1) Due to the income tax benefit in 2012, the effective tax rate as a percentage of our total income from continuing operations before income taxes is not meaningful for those periods.

In 2012, we reversed $8.2 million of uncertain tax positions and recognized an income tax benefit in the Consolidated Statements of Operations as a result of tax audit settlements and the expiration of statutes of limitations. At December 31, 2014 and 2013, we had no uncertain tax positions.

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21. Quarterly Financial Data (Unaudited)

The table below summarizes our unaudited quarterly financial data for 2014 and 2013.

	2014 Quarters				Total
	First	Second	Third	Fourth	Year
Revenues from continuing operations	$1,019,719	$1,015,049	$964,114	$847,282	$3,846,164
Operating income	$35,402	$31,257	$35,268	$30,624	$132,551
Income from continuing operations	$29,775	$21,148	$29,113	$26,166	$106,202
Net income	$29,775	$21,148	$29,113	$26,166	$106,202
Basic and diluted net income per common unit:					
Continuing operations	$0.34	$0.24	$0.33	$0.28	$1.18
Net income per common unit	$0.34	$0.24	$0.33	$0.28	$1.18
Cash distributions per common unit (1)	$0.5350	$0.5500	$0.5650	$0.5800	$2.2300
	2013 Quarters				Total
	First	Second	Third	Fourth	Year
Revenues from continuing operations	$1,014,808	$1,068,694	$1,090,293	$961,035	$4,134,830
Operating income	$30,005	$33,360	$24,092	$23,300	$110,757
Income from continuing operations	$22,704	$26,612	$17,966	$16,722	$84,004
Loss from discontinued operations	$143	$290	$508	$1,164	$2,105
Net income	$22,847	$26,902	$18,474	$17,886	$86,109
Basic and diluted net income per common unit:					
Continuing operations	$0.28	$0.32	$0.21	$0.19	$1.00
Discontinued operations	$—	$0.01	$0.01	$0.01	$0.03
Net income per common unit	$0.28	$0.33	$0.22	$0.20	$1.03
Cash distributions per common unit (1)	$0.4850	$0.4975	$0.5100	$0.5225	$2.0150

(1) Represents cash distributions declared and paid in the applicable period.

22. Condensed Consolidating Financial Information

Our $1,050 million 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 10 for additional information regarding our consolidated debt obligations.

The following is condensed consolidating financial information for Genesis Energy, L.P. and subsidiary guarantors:

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Condensed Consolidating Balance Sheet
December 31, 2014

	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	$9	$ —	$8,352	$ 1,101	$—	$9,462
Other current assets	1,378,573	—	327,819	51,781	(1,412,269)	345,904
Total current assets	1,378,582	—	336,171	52,882	(1,412,269)	355,366
Fixed Assets, at cost	—	—	1,781,158	117,900	—	1,899,058
Less: Accumulated depreciation	—	—	(245,548)	(22,509)	—	(268,057)
Net fixed assets	—	—	1,535,610	95,391	—	1,631,001
Goodwill	—	—	325,046	—	—	325,046
Other assets, net	28,421	—	269,252	146,700	(154,192)	290,181
Equity investees and other investments	—	—	628,780	—	—	628,780
Investments in subsidiaries	1,434,255	—	126,035	—	(1,560,290)	—
Total assets	$2,841,258	$ —	$3,220,894	$ 294,973	$(3,126,751)	$3,230,374
LIABILITIES AND PARTNERS' CAPITAL						
Current liabilities	$11,016	$ —	$1,751,548	$ 13,013	$(1,412,432)	$363,145
Senior secured credit facilities	550,400	—	—	—	—	550,400
Senior unsecured notes	1,050,639	—	—	—	—	1,050,639
Deferred tax liabilities	—	—	18,754	—	—	18,754
Other liabilities	—	—	15,082	157,172	(154,021)	18,233
Total liabilities	1,612,055	—	1,785,384	170,185	(1,566,453)	2,001,171
Partners' capital	1,229,203	—	1,435,510	124,788	(1,560,298)	1,229,203
Total liabilities and partners' capital	$2,841,258	$ —	$3,220,894	$ 294,973	$(3,126,751)	$3,230,374

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Condensed Consolidating Balance Sheet
December 31, 2013

	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	$20	$—	$8,061	$785	$—	$8,866
Other current assets	1,133,695	—	498,230	54,199	(1,159,767)	526,357
Total current assets	1,133,715	—	506,291	54,984	(1,159,767)	535,223
Fixed Assets, at cost	—	—	1,211,356	116,618	—	1,327,974
Less: Accumulated depreciation	—	—	(181,905)	(17,325)	—	(199,230)
Net fixed assets	—	—	1,029,451	99,293	—	1,128,744
Goodwill	—	—	325,046	—	—	325,046
Other assets, net	21,432	—	238,282	152,413	(159,185)	252,942
Equity investees and other investments	—	—	620,247	—	—	620,247
Investments in subsidiaries	1,236,164	—	124,718	—	(1,360,882)	—
Total assets	$2,391,311	$—	$2,844,035	$306,690	$(2,679,834)	$2,862,202
LIABILITIES AND PARTNERS' CAPITAL						
Current liabilities	$10,002	$—	$1,576,186	$19,660	$(1,159,295)	$446,553
Senior secured credit facilities	582,800	—	—	—	—	582,800
Senior unsecured notes	700,772	—	—	—	—	700,772
Deferred tax liabilities	—	—	15,944	—	—	15,944
Other liabilities	—	—	14,664	162,739	(159,007)	18,396
Total liabilities	1,293,574	—	1,606,794	182,399	(1,318,302)	1,764,465
Partners' capital	1,097,737	—	1,237,241	124,291	(1,361,532)	1,097,737
Total liabilities and partners' capital	$2,391,311	$—	$2,844,035	$306,690	$(2,679,834)	$2,862,202

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Condensed Consolidating Statement of Operations
Year Ended December 31, 2014

	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:						
Pipeline transportation services	$ —	$ —	$ 61,221	$ 25,232	$ —	$ 86,453
Refinery services	—	—	202,250	18,289	(13,138)	207,401
Marine transportation	—	—	229,282	—	—	229,282
Supply and logistics	—	—	3,312,273	107,752	(96,997)	3,323,028
Total revenues	—	—	3,805,026	151,273	(110,135)	3,846,164
COSTS AND EXPENSES:						
Supply and logistics costs	—	—	3,264,327	109,722	(96,997)	3,277,052
Marine transportation costs	—	—	142,793	—	—	142,793
Refinery services operating costs	—	—	117,788	17,393	(13,780)	121,401
Pipeline transportation operating costs	—	—	29,111	1,656	—	30,767
General and administrative	—	—	50,572	120	—	50,692
Depreciation and amortization	—	—	85,696	5,212	—	90,908
Total costs and expenses	—	—	3,690,287	134,103	(110,777)	3,713,613
OPERATING INCOME	—	—	114,739	17,170	642	132,551
Equity in earnings of equity investees	—	—	43,135	—	—	43,135
Equity in earnings of subsidiaries	172,828	—	1,857	—	(174,685)	—
Interest (expense) income, net	(66,626)	—	15,662	(15,675)	—	(66,639)
Income before income taxes	106,202	—	175,393	1,495	(174,043)	109,047
Income tax benefit (expense)	—	—	(3,030)	185	—	(2,845)
Income from continuing operations	106,202	—	172,363	1,680	(174,043)	106,202
NET INCOME	$ 106,202	$ —	$ 172,363	$ 1,680	$ (174,043)	$ 106,202

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Condensed Consolidating Statement of Operations
Year Ended December 31, 2013

	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:						
Pipeline transportation services	$ —	$ —	$ 60,748	$ 25,760	$—	$ 86,508
Refinery services	—	—	203,021	17,835	(14,871)	205,985
Marine transportation	—	—	152,542	—	—	152,542
Supply and logistics	—	—	3,669,241	152,460	(131,906)	3,689,795
Total revenues	—	—	4,085,552	196,055	(146,777)	4,134,830
COSTS AND EXPENSES:						
Supply and logistics costs	—	—	3,637,492	143,742	(131,906)	3,649,328
Marine transportation costs	—	—	104,676	—	—	104,676
Refinery services operating costs	—	—	128,814	16,873	(14,398)	131,289
Pipeline transportation operating costs	—	—	25,827	1,379	—	27,206
General and administrative	—	—	46,670	120	—	46,790
Depreciation and amortization	—	—	60,383	4,401	—	64,784
Total costs and expenses	—	—	4,003,862	166,515	(146,304)	4,024,073
OPERATING INCOME	—	—	81,690	29,540	(473)	110,757
Equity in earnings of equity investees	—	—	22,675	—	—	22,675
Equity in earnings of subsidiaries	134,616	—	13,399	—	(148,015)	—
Interest (expense) income, net	(48,507)	—	16,080	(16,156)	—	(48,583)
Income before income taxes	86,109	—	133,844	13,384	(148,488)	84,849
Income tax benefit (expense)	—	—	(676)	(169)	—	(845)
Income from continuing operations	86,109	—	133,168	13,215	(148,488)	84,004
Income from discontinued operations	—	—	2,105	—	—	2,105
NET INCOME	$ 86,109	$ —	$ 135,273	$ 13,215	$ (148,488)	$ 86,109

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Condensed Consolidating Statement of Operations
Year Ended December 31, 2012

	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:						
Pipeline transportation services	$ —	$ —	$ 50,106	$ 26,184	$ —	$ 76,290
Refinery services	—	—	192,083	19,999	(16,065)	196,017
Marine transportation	—	—	118,204	—	—	118,204
Pipeline transportation services	—	—	2,951,500	135,013	(109,663)	2,976,850
Total revenues	—	—	3,311,893	181,196	(125,728)	3,367,361
COSTS AND EXPENSES:						
Supply and logistics costs	—	—	2,913,127	120,280	(109,661)	2,923,746
Marine transportation costs	—	—	80,547	—	—	80,547
Refinery services operating costs	—	—	120,095	19,489	(16,107)	123,477
Pipeline transportation operating costs	—	—	21,000	894	—	21,894
General and administrative	—	—	41,715	122	—	41,837
Depreciation and amortization	—	—	57,386	3,764	—	61,150
Total costs and expenses	—	—	3,233,870	144,549	(125,768)	3,252,651
OPERATING INCOME	—	—	78,023	36,647	40	114,710
Equity in earnings of equity investees	—	—	14,345	—	—	14,345
Equity in earnings of subsidiaries	137,151	—	20,547	—	(157,698)	—
Interest (expense) income, net	(40,832)	—	16,500	(16,591)	—	(40,923)
Income before income taxes	96,319	—	129,415	20,056	(157,658)	88,132
Income tax benefit	—	—	8,903	302	—	9,205
Income from continuing operations	96,319	—	138,318	20,358	(157,658)	97,337
Loss from discontinued operations	—	—	(1,018)	—	—	(1,018)
NET INCOME	96,319	—	137,300	20,358	(157,658)	96,319

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Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2014

	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	$(148,008)	$ —	$589,643	$ 8,336	$(158,917)	$ 291,054
CASH FLOWS FROM INVESTING ACTIVITIES:						
Payments to acquire fixed and intangible assets	—	—	(442,173)	(1,309)	—	(443,482)
Cash distributions received from equity investees - return of investment	42,755	—	18,363	—	(42,755)	18,363
Investments in equity investees	(225,725)	—	(40,926)	—	225,725	(40,926)
Acquisitions	—	—	(157,000)	—	—	(157,000)
Repayments on loan to non-guarantor subsidiary	—	—	4,993	—	(4,993)	—
Proceeds from asset sales	—	—	272	—	—	272
Other, net	—	—	(1,214)	—	—	(1,214)
Net cash used in investing activities	(182,970)	—	(617,685)	(1,309)	177,977	(623,987)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Borrowings on senior secured credit facility	1,839,900	—	—	—	—	1,839,900
Repayments on senior secured credit facility	(1,872,300)	—	—	—	—	(1,872,300)
Proceeds from issuance of senior unsecured notes, including premium	350,000	—	—	—	—	350,000
Debt issuance costs	(11,896)	—	—	—	—	(11,896)
Issuance of common units for cash, net	225,725	—	225,725	—	(225,725)	225,725
Distributions to partners/owners	(200,461)	—	(200,462)	(1,252)	201,714	(200,461)
Other, net	(1)	—	3,070	(5,459)	4,951	2,561
Net cash provided by financing activities	330,967	—	28,333	(6,711)	(19,060)	333,529
Net increase (decrease) in cash and cash equivalents	(11)	—	291	316	—	596
Cash and cash equivalents at beginning of period	20	—	8,061	785	—	8,866
Cash and cash equivalents at end of period	$9	$ —	$8,352	$ 1,101	$—	$ 9,462

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Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2013

	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	$(280,155)	$ —	$547,333	$ 6,246	$(135,038)	$ 138,386
CASH FLOWS FROM INVESTING ACTIVITIES:						
Payments to acquire fixed and intangible assets	—	—	(332,024)	(11,095)	—	(343,119)
Cash distributions received from equity investees - return of investment	23,963	—	12,432	—	(23,963)	12,432
Investments in equity investees	(263,574)	—	(94,551)	—	263,574	(94,551)
Acquisitions	—	—	(230,880)	—	—	(230,880)
Repayments on loan to non-guarantor subsidiary	—	—	4,512	—	(4,512)	—
Proceeds from assets sales	—	—	1,910	—	—	1,910
Other, net	—	—	(1,622)	—	—	(1,622)
Net cash used in investing activities	(239,611)	—	(640,223)	(11,095)	235,099	(655,830)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Borrowings on senior secured credit facility	1,593,300	—	—	—	—	1,593,300
Repayments on senior secured credit facility	(1,510,500)	—	—	—	—	(1,510,500)
Proceeds from issuance of senior unsecured notes, including premium	350,000	—	—	—	—	350,000
Debt issuance costs	(8,157)	—	—	—	—	(8,157)
Issuance of ownership interests to partners for cash	263,574	—	263,574	—	(263,574)	263,574
Distributions to partners/owners	(168,441)	—	(168,441)	9,401	159,040	(168,441)
Other, net	—	—	(5,396)	(3,825)	4,473	(4,748)
Net cash provided by (used in) financing activities	519,776	—	89,737	5,576	(100,061)	515,028
Net increase (decrease) in cash and cash equivalents	10	—	(3,153)	727	—	(2,416)
Cash and cash equivalents at beginning of period	10	—	11,214	58	—	11,282
Cash and cash equivalents at end of period	$20	$ —	$8,061	$ 785	$—	$ 8,866

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Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2012

	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	$(70,083)	$ —	$362,855	$ 25,186	$(128,654)	$ 189,304
CASH FLOWS FROM INVESTING ACTIVITIES:						
Payments to acquire fixed and intangible assets	—	—	(137,362)	(9,094)	—	(146,456)
Cash distributions received from equity investees - return of investment	27,878	—	14,909	—	(27,878)	14,909
Investments in equity investees	(169,421)	—	(63,749)	—	169,421	(63,749)
Acquisitions	—	—	(205,576)	—	—	(205,576)
Repayments on loan to non-guarantor subsidiary	—	—	4,078	—	(4,078)	—
Proceeds from asset sales	—	—	773	—	—	773
Other, net	—	—	(1,557)	49	—	(1,508)
Net cash used in investing activities	(141,543)	—	(388,484)	(9,045)	137,465	(401,607)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Borrowings on senior secured credit facility	1,674,400	—	—	—	—	1,674,400
Repayments on senior secured credit facility	(1,583,700)	—	—	—	—	(1,583,700)
Proceeds from issuance of senior unsecured notes	101,000	—	—	—	—	101,000
Debt issuance costs	(7,105)	—	—	—	—	(7,105)
Issuance of ownership interests to partners for cash	169,421	—	169,421	—	(169,421)	169,421
Distributions to partners/owners	(142,383)	—	(142,383)	(14,183)	156,566	(142,383)
Other, net	—	—	623	(3,532)	4,044	1,135
Net cash provided by financing activities	211,633	—	27,661	(17,715)	(8,811)	212,768
Net increase in cash and cash equivalents	7	—	2,032	(1,574)	—	465
Cash and cash equivalents at beginning of period	3	—	9,182	1,632	—	10,817
Cash and cash equivalents at end of period	$10	$ —	$11,214	$ 58	$—	$ 11,282