GENESIS ENERGY LP
Form 10-K
February 26, 2013

Table of Contents

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, 2012
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. x
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, 2012 (the last business day of Registrant's most recently completed second fiscal quarter) was approximately $1.6 billion based on $29.07 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 22, 2013, the Registrant had 81,162,755 Class A common units outstanding.

Table of Contents

GENESIS ENERGY, L.P.
2012 FORM 10-K ANNUAL REPORT
Table of Contents

Definitions

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

Bbl or Barrel: One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to 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;

Table of Contents

- 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.

Table of Contents

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 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, 2012.

We provide an integrated suite of services to oil producers, refineries, 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. 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. Since our acquisition of all of the equity interest in our general partner in December 2010, our outstanding common units and waiver units representing limited partner interest constitute all of the economic equity interest in us.

We manage our businesses through three divisions that constitute our reportable segments – Pipeline Transportation, Refinery Services, and Supply and Logistics.

Pipeline Transportation Segment

Overview

We own interests in approximately 1,500 miles of crude oil pipelines located in the Gulf Coast region of the United States. We also own two CO_2 pipelines. Our pipelines generate cash flows from fees charged to customers or substantially similar arrangements that otherwise limit our exposure to changes in commodity prices.

Crude Oil Pipelines

We own interests in three onshore crude oil pipeline systems, with approximately 460 miles of pipe located primarily in Alabama, Florida, Mississippi and Texas. The FERC regulates the rates charged by two of our onshore systems to their customers. The rates for the other onshore pipeline are regulated by the Railroad Commission of Texas. We also own interests in various offshore crude oil pipeline systems, with approximately 1,050 miles of pipe and an aggregate design capacity of approximately 1,300 MBbls per day, located offshore in the Gulf of Mexico, a producing region representing approximately 20% of the crude oil production in the United States in 2012. 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 the largest crude oil pipeline (in terms of both length and design capacity) located in the Gulf of Mexico. We acquired our interest in Poseidon, along with certain other pipeline interests, on January 3, 2012.

CO_2 Pipelines

We own interests in 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. 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. We receive a fixed quarterly payment under the NEJD arrangement. Payments on the Free State pipeline are dependent on throughput.

Refinery Services Segment

We primarily (i) provide services to nine refining operations located primarily in Texas, Louisiana, Arkansas 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")

Table of Contents

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 four 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.

Supply and Logistic Segment

We provide supply and logistics services primarily 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, rail loading and unloading facilities, and barges. We have access to a suite of more than 300 trucks, 350 trailers, 180 rail cars, and terminals and tankage with 1.7 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 marine operations include access to 50 barges with a combined transportation capacity of 1.5 million barrels of heavy refined petroleum products, including asphalt, and 22 push/tow boats. Approximately half of our barges would be capable of transporting crude oil if we were to make minor modifications. 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.

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 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.

6

Table of Contents

Competitive Strengths

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

- Our businesses encompass a balanced, diversified portfolio of customers, operations and assets. We operate three business segments and own and operate assets that enable us to provide a number of services to oil and CO_2 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.
- Through our NaHS sales, we have indirect exposure to fast-growing, developing economies outside of the U.S. We sell NaHS to the mining and pulp and paper industries, which sell copper and other mined materials and paper products in the global market.
- We have lower commodity price risk exposure. The volumes of crude oil, refined products or intermediate feedstocks that 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. 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 our processing rates to maintain a balance between NaHS supply and demand.
- 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 consecutive quarters as of our most recent distribution declaration. During this period, twenty-five of those quarterly increases have been 10% or greater year-over-year.
- Our pipeline transportation and related assets are strategically located. Our crude oil pipelines are located in the Gulf of Mexico and provide our customers access to multiple delivery points. 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 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 refinery services market can provide us with an advantage when evaluating new opportunities and/or markets.
- 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.
- We are financially flexible and have significant liquidity. As of December 31, 2012, we had $483.3 million available under our $1 billion credit agreement, including up to $86.1 million available under the $150 million petroleum products inventory loan sublimit, and $83.3 million available for letters of credit. Our inventory borrowing base was $63.9 million at December 31, 2012.
- 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 Growth Initiatives

The following is a brief listing of developments since December 31, 2011. Additional information regarding most of these items may be found elsewhere in this report.

Gulf Coast Infrastructure

We plan to invest approximately $125 million to improve existing assets and develop 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, constructing a new 18-mile 20-inch diameter crude oil pipeline connecting Port Hudson to the Baton Rouge Maryland Terminal and continuing downstream to the Anchorage Tank Farm and building a new crude oil unit

Table of Contents

train facility at the Maryland Terminal. The Port Hudson upgrades and new crude oil pipeline are expected to be completed by the end of 2013 and the Maryland Terminal completion is scheduled for the second quarter of 2014.

Deepwater Gulf of Mexico Pipeline Joint Venture

Southeast Keathley Canyon Pipeline Company LLC, or SEKCO, a joint venture with Enterprise Products Partners, L.P., is constructing a deepwater pipeline serving the Lucius development area in southern Keathley Canyon of the Gulf of Mexico. SEKCO has entered into 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 pipeline to provide capacity for additional projects in the deepwater Gulf of Mexico. Enterprise Products serves as construction manager and will be the operator of the new pipeline.

The 149-mile, 18-inch diameter pipeline, designed to have a 115,000 barrel per day capacity, will connect the Lucius-truss spar floating production platform to an existing junction platform at South Marsh Island that is part of the recently acquired Poseidon pipeline system described above. The new pipeline is expected to begin service by mid-2014. 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."

Texas City Projects

In the fourth quarter of 2012, we completed two projects to increase the services we provide to producers and refiners. We acquired three above-ground storage tanks located in Texas City, Texas and an existing barge dock at the same location, all approximately 1.5 miles from our existing Texas pipeline system. We also constructed a truck station and tankage in West Columbia, Texas to provide incremental transportation service for the Eagle Ford Shale and other Texas production through our pipeline system to refining markets in the greater Houston/Texas City area. We are able to handle approximately 40,000 barrels per day of crude oil through the Texas City terminal. In addition, we have initiated construction of a 18-inch diameter loop of our existing crude oil pipeline into Texas City, supported by a term contract with one of our refining customers, which we expect will allow us to significantly expand our total service capabilities into the Texas City area by the late second quarter or early third quarter of 2013.

HollyFrontier Tulsa Project

We are installing a new sour gas processing facility at Holly Refining and Marketing's refinery complex located in Tulsa, Oklahoma. The new facility, expected to be operational in mid-2013, will remove a portion of the sulfur from the crude oil refined at Holly's complex and is expected to result in potential additional capacity of 24,000 DST per year of NaHS.

Rail Projects

In August 2012, we completed construction on the first phase of a new crude-by-rail unloading terminal connected to our existing crude oil pipeline at Walnut Hill, Florida. This facility is capable of handling unit train shipments of oil for direct deliveries to an existing refinery customer and indirect deliveries (through third-party common carriers) to multiple other markets in the Southeast at the option of the shippers. We anticipate the second phase of the terminal, which includes a 100,000 barrel storage tank and related equipment, to be fully operational in March of 2013.

In 2012, we completed initial phase construction of a crude oil rail loading facility in Wink, Texas, giving us the capability to load Genesis and third party railcars designed to move West Texas production to more highly valued markets. Additional expansion of this facility, which we estimate will be fully operational by late third quarter or early fourth quarter of 2013, will allow us to increase the capacity of this system.

In 2012, we commenced construction on a crude oil rail unloading/loading facility at our existing terminal located in Natchez, Mississippi, which is designed to facilitate the movement of Canadian bitumen/dilbit to Gulf Coast markets. The facility will have the capability to unload bitumen/dilbit as well as loading diluent for backhauls to Canada. In the first quarter of 2013, we steamed and unloaded into tanks the first railcars loaded with bitumen/dilbit originating in Alberta, Canada.

Wyoming Gathering Project

We are re-activating portions of the related gathering and transportation pipelines in Wyoming and constructing a new pipeline which will connect to the Casper, Wyoming markets. We anticipate the re-activation of existing pipelines and the new pipeline will be completed in the second quarter of 2013.

Thirty Consecutive Distribution Rate Increases

We have increased our quarterly distribution rate for thirty consecutive quarters. During this period, twenty-five of those quarterly increases have been 10% or greater year-over-year. On February 14, 2013, we paid a quarterly cash distribution of $0.4850 (or $1.94 annually) per unit to unitholders of record as of February 1, 2013, an increase per unit of $0.0125 (or

Table of Contents

2.6%) from the distribution in the prior quarter, and an increase of 10.2% from the distribution in February 2012. 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.

Organizational Structure

The following chart depicts our organizational structure at December 31, 2012.

Description of Segments and Related Assets

We conduct our business through three primary segments: Pipeline Transportation, Refinery Services 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.

Pipeline Transportation

Overview

We own three onshore crude oil common carrier pipelines, interests in several offshore crude oil pipeline systems in the Gulf of Mexico and two CO_2 pipelines. Our core pipeline transportation business is the transportation of crude oil for others for a fee.

Table of Contents

Crude Oil Pipelines

Onshore Crude Oil Pipelines.

Through the onshore pipeline systems 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 three onshore common carrier crude oil pipeline systems: the Texas System, the Jay System and the Mississippi System.

	Texas System	Jay System	Mississippi System
Product	Crude Oil	Crude Oil	Crude Oil
Interest Owned	100%	100%	100%
System Miles	90	135	235
Approximate Owned and leased tankage storage capacity (Bbls)	220,000	230,000	247,500
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
Rate Regulated	TXRRC	FERC	FERC

- Texas System. Our Texas System transports crude oil from West Columbia to several delivery points near Houston, Texas. The Texas System receives all of its volume from connections to other pipeline carriers. 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. The system also includes gathering connections to approximately 35 wells, additional oil storage capacity of 20,000 barrels in the field and a delivery connection to a refinery in Alabama.
- 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. The 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.

Offshore Crude Oil Pipelines.

We own interests in several crude oil pipelines located offshore in the Gulf of Mexico, a producing region representing approximately 20% of the crude oil production in the United States in 2012. CHOPS is the largest crude oil pipeline (in terms of both length and design capacity) located in the Gulf of Mexico. The table below reflects our interests in our operating offshore crude oil pipelines.

Table of Contents

	CHOPS	Poseidon	Odyssey	Eugene Island
Product	Crude Oil	Crude Oil	Crude Oil	Crude Oil
Interest Owned [(1)]	50%	28%	29%	23%
System Miles	380	367	120	183
Capacity (Bbls/day)	500,000	400,000	200,000	200,000
2012 Throughput (Bbls/day)	96,664	211,375	36,157	15,191
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)
Rate Regulated	No	No	No	FERC
In-Service Date	2004	1996	1998	1983

(1) We acquired our interests in CHOPS in November 2010 and our interests in our other offshore pipelines in January 2012.

- CHOPS. CHOPS is comprised of 24- to 30-inch diameter pipelines to deliver crude oil from developments 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. The pipeline has significant available capacity to accommodate future growth in the fields from which the production is dedicated to the pipeline as well as to transport volumes from non-dedicated fields both currently in production and to be developed in the future.
- 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.
- 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.
- SEKCO Pipeline. As described in “Recent Developments” we entered into a joint venture with Enterprise Products to construct a deepwater pipeline serving the Lucius development area in southern Keathley Canyon of the Gulf of Mexico. The pipeline is expected to begin service by mid-2014.

Table of Contents

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	NEJD System [(1)]
Product	CO_2	CO_2
Interest owned	100%	100%
System miles	86	183
Pipeline diameter	20"	20"
Location	Jackson Dome near Jackson, MS to East Mississippi	Jackson Dome near Jackson, MS to Donaldsonville, LA
Rate Regulated	No	No

(1) Subject to a fixed payment agreement.

Our Free State pipeline extends from CO_2 source fields near Jackson, Mississippi to oil fields in eastern Mississippi. We have a twenty-year 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 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 all obligations and liabilities with respect to that system. Currently, Denbury also has rights to exclusive use of our Free State pipeline.

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. The anchor customers for CHOPS (including subsidiaries of BP p.l.c., BHP Billiton Group and Chevron Corporation) dedicated their production from approximately 86,400 acres to CHOPS for the life of the reserves underlying such acreage, which dedications included Mad Dog and Atlantis fields as well as other deepwater oil discoveries. Those producer agreements include both firm and, to the extent CHOPS has any remaining capacity, interruptible capacity arrangements. Since its formation, CHOPS has entered into handling arrangements with numerous other producers pursuant to both firm and interruptible capacity arrangements covering deepwater discoveries, including Constitution, Ticonderoga, K2, Shenzi, Front Runner, Cottonwood and Tahiti. Our primary customers for our Poseidon system include BHP Billiton Group, Repsol, Hess and Anadarko Petroleum Corporation, primarily from the Shenzi, Allegheny and K2 Complex developments in addition to other deepwater developments. Anadarko, Chevron, ENI, Marathon, Murphy, Statoil and Hess have dedicated their production to Poseidon from the Allegheny, Marco Polo, Droshky, Bald Plate, Front Runner and Lobster fields.

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

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.

Table of Contents

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 nine refining operations primarily located in Texas, Louisiana, Arkansas 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 refinery services footprint includes terminals in the Gulf Coast, the Midwest, Montana, Utah, British Columbia and South America. We also utilize railcars, ships, barges and trucks to transport product. In conjunction with our supply and logistics segment, we sell and deliver NaHS and caustic soda to over 100 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. Our refinery services contracts are typically long-term in nature. The average remaining life of our refinery services contracts is four years. 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 nine refining locations, and we manage sulfur removal by exclusive rights to market NaHS produced at three third-party sites. While some of our customers have elected to own the sulfur removal facilities located at their refineries, we operate those facilities. These 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 revenues. Approximately 10% of the revenues of the refinery services segment in 2012 resulted from sales to Kennecott Utah Copper, a subsidiary of Rio Tinto plc. 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 copper mining. We also supply caustic soda to some of the refineries in which we operate for use in cleaning processing equipment.

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.

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 truck 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 or 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 and Mississippi. 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. 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 primarily with NYMEX derivatives to offset the remaining price risk. By utilizing our network of trucks, rail, barges, terminals and pipelines, we are able to provide transportation related services to crude oil producers and refiners as well as enter into back-to-back gathering and marketing arrangements with these same parties. 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 50,000 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 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 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.

Our refined products supply and logistics operations are concentrated in the Gulf Coast region, principally Texas and Louisiana. 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 their 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. By utilizing our broad network of relationships and logistics assets, including our terminal accessibility, 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. Alternatively, our refinery customers may choose to manufacture such refined products depending on a number of economic and operating factors, and therefore we cannot predict the timing of contribution margins related to our blending services. We recently completed two crude oil rail loading/unloading facilities in Walnut Hill, Florida and Wink, Texas which provide synergies to our existing asset footprint. An additional crude oil rail facility in Natchez, Mississippi, estimated to be completed in the first quarter of 2013, will facilitate the movement of Canadian bitumen/dilbit markets in the Gulf of Mexico. We generally earn a fee for loading or unloading railcars at these facilities. Our industrial gases supply and logistics operations supply CO_2, which we acquire pursuant to our volumetric production payments (also known as VPPs) to industrial customers currently under four long-term contracts, with an average remaining contract life of five years. Our existing customer contracts expire between 2015 and 2023. At December 31, 2012, we had approximately 53.3 Bcf of CO_2 remaining under the VPPs. All of our CO_2 supply is currently from our interests—our VPPs—in fields producing naturally occurring CO_2. We do not expect to renew or replace our CO_2 supply agreements.

14

Table of Contents

Within our supply and logistics business segment, we employ many types of logistically flexible assets. These assets include 300 trucks, 350 trailers, 180 rail cars, 50 barges with approximately 1.5 million barrels of refined products transportation capacity, 22 push/tow boats, and terminals and other tankage with 1.7 million barrels of leased and owned storage capacity in multiple locations along the Gulf Coast, accessible by truck, rail or barge. Our leased rail cars consist of approximately 80 refined product rail cars and 100 crude oil rail cars. We will take delivery of approximately 400 leased crude oil rail cars in 2013. Our marine fleet 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, including the Red, Ouachita and Mississippi Rivers. Approximately half of our barges would be capable of transporting crude oil if we were to make minor modifications.

Customers

Our supply and logistics business encompasses hundreds of producers and customers, for which we provide transportation related services, as well as gather from and market to crude oil, refined products and CO_2. During 2012, more than 10% of our consolidated revenues were generated from Shell. We do not believe that the loss of any one customer for crude oil, petroleum products or CO_2 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 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 $19.3 million, $19.7 million and $14.5 million in 2012, 2011 and 2010, 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 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 the obligations of integrated and independent energy companies with stable payment experience. The credit risk related to contracts that are traded on the NYMEX is limited due to the daily cash settlement procedures and other NYMEX requirements.

When we market crude oil 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 950 employees at December 31, 2012. 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 be filed with FERC and posted publicly.

Table of Contents

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 the 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 the 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 portion of the rate increase resulting from application of the index is substantially in excess of the 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, or agreements between shippers and the oil pipeline company that the rate is acceptable, or Settlement Rates. The pipeline tariff rates on our Mississippi and Jay Systems are either rates that were grandfathered and have been changed 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. Most 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 tow boats, barges and marine equipment create maritime obligations involving property, personnel and cargo 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.

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 American Bureau of Shipping, or 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 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 that provides 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.

Table of Contents

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 require the acquisition of and compliance with permits for regulated activities, limit or prohibit operations on environmentally sensitive lands such as wetlands or wilderness areas or areas inhabited by endangered or threatened species, result in capital expenditures to limit or prevent emissions or discharges, and place burdensome restrictions on our operations, including the management and disposal of wastes. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, including the assessment of monetary penalties, the imposition of investigatory and remedial obligations, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and the issuance of orders enjoining future operations or imposing additional compliance requirements. Changes in environmental laws and regulations occur frequently, typically increasing in stringency through time, and any changes that result in more stringent and costly operating restrictions, emission control, waste handling, disposal, cleanup, and other environmental requirements have the potential to have a material adverse effect on our operations. While we believe that we are in substantial compliance with current environmental laws and regulations and that continued compliance with existing requirements would not materially affect us, there is no assurance that this trend will continue in the future. Revised or new additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and cash flows.

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

Table of Contents

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.

Air Emissions

The Federal Clean Air Act, 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 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 by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the CAA. Among such regulations, the EPA adopted its "tailoring rule," which became effective in January 2011 and establishes new thresholds that determine which stationary sources of greenhouse gases are required to obtain permits and implement best available control technology standards on account of their greenhouse gas emission levels. The EPA has also adopted rules limiting greenhouse gas emissions from new motor vehicles and creating reporting requirements for large greenhouse gas emissions sources.

Further, Congress has considered various proposals to reduce greenhouse gas emissions that may impose a carbon emissions tax, a cap-and-trade program or other programs aimed at carbon reduction, including the American Clean Energy and Security Act of 2009, passed by the U.S. House of Representatives in June 2009 and a similar bill in the U.S. Senate. Either bill would have established an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases including carbon dioxide and methane that may contribute to the warming of the earth's atmosphere and other climatic changes. The current administration supports legislation to reduce greenhouse gas emissions through an emission allowance system. As allowances under such a system would be expected to significantly escalate in cost over time, the net effect of any potential cap-and-trade legislation would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products and natural gas. In addition, at least one-third of the states, either individually or through multi-state regional initiatives, have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or greenhouse gas cap-and-trade programs. Our compliance with any future legislation or regulation of greenhouse gases, 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.

Table of Contents

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 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 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

Table of Contents

practicable after we electronically file the material with, or furnish it to, the SEC. Additionally, these documents are available at the SEC's website (www.sec.gov). Information on our website is not incorporated into this Form 10-K or our other securities filings and is not a part of this Form 10-K or our other securities filings.

Item 1A. Risk Factors

Risks Related to Our Business

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 been, and may continue to 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 continue to experience volatility and the availability of funds remains 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.

Economic developments in the United States and worldwide in credit markets and concerns about economic growth could impact our operations and materially reduce our profitability and cash flows.

Continued uncertainty in the credit markets and concerns about local and global economic growth have had a significant adverse impact on global financial markets. If these disruptions, which have occurred over the last several years, reappear, they could negatively impact our cash flows and profitability. Tightening of the credit markets, lower levels of liquidity in many financial markets, and extreme volatility in fixed income, credit and equity markets could limit our access to capital.

Additionally, significant decreases in our operating cash flows could affect the fair value of our long-lived assets and result in impairment charges. At December 31, 2012, we had $325 million of goodwill recorded on our Consolidated Balance Sheet.

Fluctuations in interest rates could adversely affect our business.

We have exposure to movements in interest rates. The interest rates on our credit facility ($500 million outstanding at December 31, 2012) 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 refinery services, pipeline transportation, and supply and logistics businesses, which fluctuate from quarter to quarter based on, among other things:

Table of Contents

- 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 trucking, barge and pipeline transportation services;
- the demand for our terminal storage services;
- the level of our operating costs;
- the effect of worldwide energy conservation measures;
- governmental regulations and taxes;
- the level of our general and administrative costs; and
- prevailing economic conditions.

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

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

Our ability to pay distributions each quarter depends primarily on our cash flow, including cash flow from financial reserves and working capital borrowings, and 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, 2012, we had approximately $500 million outstanding of senior secured indebtedness and an additional $350.9 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;

Table of Contents

- 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 facilities. 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.

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 are experiencing.

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 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 pipeline transportation operations are dependent upon demand for crude oil by refiners in the Midwest and on the 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' need 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 commodity 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 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. 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 transported by our pipelines. As a result, we may experience declines in our margin and profitability if our volumes decrease.

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 throughput, volumes and, in some cases, margins.

Table of Contents

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 any of 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.

We sell petroleum products to many wholesalers and end-users that are not large companies and are privately-owned operations. While those sales are not large volume sales, they tend to be frequent transactions such that a large balance can develop quickly. 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.

Additionally, many of our customers were impacted by the weakened economic conditions 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.

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 2012, approximately 70% 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.

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 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 greenhouse gases 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 by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the CAA. Among several such regulations, the EPA adopted its "tailoring rule," which became effective in January 2011 and establishes new thresholds that determine which stationary sources of greenhouse gases are required to obtain permits and implement best available control technology standards on account of their greenhouse gas emission levels. The EPA has also adopted rules limiting greenhouse gas emissions from new motor vehicles and creating reporting requirements for large greenhouse gas emissions sources. Further, Congress has considered various proposals to reduce greenhouse gas emissions that may impose a carbon emissions tax, a cap-and-trade program or other programs aimed at carbon reduction, including the American Clean Energy and

Table of Contents

Security Act of 2009, passed by the U.S. House of Representatives in June 2009 and a similar bill in the U.S. Senate. Either bill would have established an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases including carbon dioxide and methane that may contribute to the warming of the earth's atmosphere and other climatic changes. The current administration supports legislation to reduce greenhouse gas emissions through an emission allowance system. As allowances under such a system would be expected to significantly escalate in cost over time, the net effect of any potential cap-and-trade legislation would be to impose increasing costs on the combustion of carbon-based fuels such as crude oil, refined petroleum products and natural gas. In addition, at least one-third of the states, either individually or through multi-state regional initiatives, have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or greenhouse gas cap-and-trade programs. Our compliance with any future legislation or regulation of greenhouse gases, 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 greenhouse gases 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 greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas 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.

In addition, some scientists have concluded that increasing concentrations of greenhouse gases in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climate events; if any such effects were to occur, they could have an adverse effect on our assets and operations.

Regulation of the rates, terms and conditions of services and a changing regulatory environment could affect our cash flow.

The FERC regulates certain of our energy infrastructure assets engaged in interstate operations. Our intrastate pipeline operations are regulated by state 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 flows.

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:

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- 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

Table of Contents

- 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.

The 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.

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.

Table of Contents

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

Due to the nature of joint ventures, each participant (including us) in our material joint ventures has made substantial investments (including contributions and other commitments) in that joint venture and, accordingly, has required that the relevant charter documents contain certain features designed to provide each participant with the opportunity to participate in the management of the joint venture and to protect its investment in that joint venture, as well as any other assets which may be substantially dependent on or otherwise affected by the activities of that joint venture. These participation and protective features include a corporate governance structure that consists of a management committee composed of four members, only two 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 participant and/or the lenders of our joint ventures, 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.

Due to our significant relationships with it, adverse developments concerning Denbury could adversely affect us, even if we have not suffered any similar developments.

We have some important relationships with Denbury. It is the operator of our largest CO_2 pipeline and the operator of the fields that produce our CO_2 reserves. We are also parties to agreements with Denbury, including the lease of our NEJD System and the transportation arrangements related to the Free State pipeline. Denbury ships substantially all of the crude oil that is shipped on our Mississippi System. We could be adversely affected if Denbury experiences any adverse developments or fails to pay us for our services on a timely basis or fails to meet its obligations to us.

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.

Table of Contents

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.

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, 2012, we have a number of significant unitholders. For example, certain members of the Davison family (including their affiliates) and management owned approximately 18.4 million or 23% of our common units. We also have other unitholders that may 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 17% 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 business strategies, mergers, business combinations, acquisitions or dispositions of significant assets, issuances of additional partnership securities, incurrence of debt or other financing and the payment of distributions. In addition, the existence of a controlling group (if one were to form) may have the effect of making it difficult for, or may discourage or delay, a third party from seeking to acquire us, which may adversely affect the market price of our common units. Further, conflicts of interest may arise between us and other entities for which members of the Davison family serve as officers or directors. In resolving any conflicts that may arise, such members of the Davison family may favor the interests of another entity over our interests.

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

- our general partner is allowed to take into account the interest of parties other than us, such as one or more of its affiliates, in resolving conflicts of interest;
- our general partner may limit its liability and reduce its fiduciary duties, while also restricting the remedies available to our unitholders for actions that, without such limitations, might constitute breaches of fiduciary duty;
- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional partnership securities, reimbursements and enforcement of obligations to the general partner and

Table of Contents

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 may 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 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.

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.

Your 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. You could be liable for any and all of our obligations as if you 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
- your 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.

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.

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.

Table of Contents

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 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.

Table of Contents

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.

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

Table of Contents

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.

Table of Contents

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)
2011			
1st Quarter	$29.83	$25.03	$ 0.4000
2nd Quarter	$29.08	$25.35	$ 0.4075
3rd Quarter	$28.12	$20.85	$ 0.4150
4th Quarter	$28.33	$21.82	$ 0.4275
2012			
1st Quarter	$33.81	$27.62	$ 0.4400
2nd Quarter	$31.40	$26.70	$ 0.4500
3rd Quarter	$34.12	$28.80	$ 0.4600
4th Quarter	$36.38	$30.86	$ 0.4725

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

At February 22, 2013, we had 81,162,755 Class A common units outstanding. As of December 31, 2012, the closing price of our common units was $35.72 and we had approximately 38,200 record holders of our common units, which include holders who own units through their brokers “in street name.”

After holders of our Waiver Units receive a minimal preferential quarterly distribution, we distribute all of our available cash, as defined in 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 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.

Table of Contents

Item 6. Selected Financial Data

The table below includes selected financial and other data for the Partnership for the years ended December 31, 2012, 2011, 2010, 2009 and 2008 (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,				
	2012 (1)	2011 (1)	2010 (1)	2009 (1)	2008 (1)
Income Statement Data:					
Revenues:					
Supply and logistics	$3,797,750	$2,825,768	$1,894,612	$1,243,044	$1,870,063
Refinery services	196,017	201,711	151,060	141,365	225,374
Pipeline transportation	76,290	62,190	55,652	50,951	46,247
Total revenues	$4,070,057	$3,089,669	$2,101,324	$1,435,360	$2,141,684
Net income (loss) (2)	$96,319	$51,249	$(50,541)	$6,178	$25,825
Net income (loss) attributable to Genesis Energy, L.P. (2)	$96,319	$51,249	$(48,459)	$8,063	$26,089
Net income (loss) available to Common Unitholders	$96,319	$51,249	$19,929	$20,186	$23,006
Net income attributable to Genesis Energy, L.P. per Common Unit: Basic and Diluted	$1.23	$0.75	$0.49	$0.51	$0.59
Cash distributions declared per Common Unit	$1.8225	$1.6500	$1.4900	$1.3650	$1.2225
Balance Sheet Data (at end of period):					
Current assets	$404,034	$376,104	$252,538	$189,244	$168,127
Total assets	$2,109,664	$1,730,844	$1,506,735	$1,148,127	$1,178,674
Long-term liabilities	$880,518	$688,778	$630,757	$387,766	$394,940
Partners' capital:					
Genesis Energy, L.P.	$916,495	$792,638	$669,264	$595,877	$632,658
Noncontrolling interests	—	—	—	23,056	24,804
Total partners' capital	$916,495	$792,638	$669,264	$618,933	$657,462
Other Data:					
Maintenance capital expenditures (3)	4,430	4,237	2,856	4,426	4,454
Volumes—continuing operations:					
Onshore crude oil pipeline (barrels per day)	92,897	82,712	67,931	60,262	64,111
Offshore crude oil pipeline (barrels per day) (4)	359,387	120,723	149,270	—	—
CO_2 pipeline (Mcf per day) (5)	186,479	169,962	167,619	154,271	160,220
NaHS sales (DST)	142,712	147,670	145,213	107,311	162,210
NaOH sales (DST)	77,492	99,702	93,283	88,959	68,647
Crude oil and petroleum products (barrels per day)	94,043	71,043	61,012	48,117	47,569

(1)

Our operating results and financial position have been affected by acquisitions, most notably the acquisition of interests in several Gulf of Mexico crude oil pipeline systems from Marathon Oil Company, including its 28% interest in Poseidon Oil Company, L.L.C., its 29% interest in Odyssey Pipeline, L.L.C. and its 23% interest in the Eugene Island Pipeline System in January 2012, the acquisition of the black oil barge business of Florida Marine Transporters, Inc. in August 2011, the 50% equity interest acquisition in CHOPS in November 2010, the acquisition of the remaining 51% ownership interest in DG Marine in July 2010 and the Grifco acquisition in July 2008. The results of these operations are included in our financial results prospectively from the acquisition date. For additional

Table of Contents

information regarding our acquisitions during 2012, 2011 and 2010, 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 and $14.1 million for 2009, see Note 15 to our Consolidated Financial Statements in Item 8.

(3) Maintenance capital expenditures are capital expenditures to replace or enhance partially or fully depreciated assets to sustain the existing operating capacity or efficiency of our assets and extend their useful lives.

(4) Includes barrels per day for CHOPS for the period we owned the pipeline in 2010.

(5) Volume per day for the period we owned the Free State CO_2 pipeline in 2008.

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 in the Gulf Coast region of the United States, primarily Texas, Louisiana, Arkansas, Mississippi, Alabama, Florida 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 provide an integrated suite of services to oil producers, refineries, 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. 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. Since our acquisition of all of the equity interest in our general partner in December 2010, our outstanding common units and waiver units representing limited partner interest constitute all of the economic equity interest in us.

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

- Overview of 2012 Results and Operational Update
- 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 2012 Results and Operational Update

We reported net income of $96.3 million, or $1.23 per common unit, in 2012 compared to net income of $51.2 million, or $0.75 per common unit, in 2011.

Segment Margin (as defined below in "Financial Measures") was $262.3 million in 2012, an increase of $59.8 million, or 30%, as compared to 2011. This increase resulted from improvement in Segment Margin in our pipeline transportation and supply and logistics segments of 42% and 55%, respectively. The contribution from our interests in certain Gulf of Mexico pipelines that we acquired in 2012 and higher crude oil tariff revenues were the primary factors increasing pipeline transportation segment margin. Results for our pipeline transportation segment were somewhat reduced during both years due to ongoing improvements at several dedicated fields. Improvements at those fields were substantially completed late in the third quarter of 2012. Our supply and logistics segment benefited from acquisitions and other growth initiatives completed in the second half of 2011 as well as higher volumes handled by our expanded trucking and barge fleets. Our refinery services segment margin decreased 2% primarily as a result of increased costs due to longer than anticipated refinery turnarounds at some of our largest refinery service locations in the first half of 2012. To ensure uninterrupted NaHS supplies to our customers, we incurred increased costs as a result of processing at and shipping from less efficient locations.

The information below provides certain updates regarding various operations and projects:

- Cameron Highway Pipeline. Production from several fields dedicated to our Cameron Highway pipeline in the offshore Gulf of Mexico began to ramp back up in August 2012 after an extended period of maintenance on the third-party operated surface and sub-sea production facilities, and total throughput levels on the pipeline have returned to levels last seen in the first quarter of 2011.

- Gulf Coast Infrastructure.We plan to invest approximately $125 million to improve existing assets and develop 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, constructing a new 18-mile 20-inch diameter crude oil pipeline connecting Port Hudson to the Baton Rouge Maryland Terminal and continuing downstream to the Anchorage Tank Farm and building a new crude oil unit train facility at the Maryland Terminal. The Port Hudson upgrades and new crude oil pipeline are expected to be completed by the end of 2013 and the Maryland Terminal completion is scheduled for the second quarter of 2014.

- Walnut Hill Rail Facility. We continue to receive unit trains of crude oil at Walnut Hill, Florida for further delivery downstream on our Jay Pipeline System, and would anticipate our new tank and related facilities to be fully operational in March of 2013, allowing us to handle more trains, more efficiently.

- Wink Rail Facility. At our new crude loading facility outside Wink, Texas in the Permian Basin, we have continued to support manifest service of crude oil volumes and in early February 2013 loaded our first full unit train. Construction of our tanks and expanded trucking capabilities remains on track to be fully operational by late third quarter or early fourth quarter of 2013.

- Natchez Terminal. At our terminal in Natchez, Mississippi, we have steamed and unloaded into tanks the first railcars loaded with bitumen/dilbit originating in Alberta, Canada. As volumes continue to ramp up, we will begin loading barges for further shipment to refineries along the Mississippi River.

- Texas City Facility. We have commissioned our new crude oil terminal and barge dock in Texas City. We would expect the terminal and barge dock to see increasing levels of throughput in the latter half of 2013 upon the completion of our new 18-inch pipeline from Webster to Texas City in the late second quarter or early third quarter of 2013.

- Wyoming. We have entered into an agreement with a local refinery in Wyoming which will support our investment to expand and place into service certain segments of our crude oil gathering system in the Niobrara shale development in Wyoming, with start-up operations expected in the second quarter of 2013.

- SEKCO. Construction has commenced on the SEKCO lateral in the Keathley Canyon area of the deepwater Gulf of Mexico, and we expect significant contribution from this investment beginning mid-2014.

Distribution Increase

On January 10, 2013, we declared our thirtieth consecutive increase in our quarterly distribution to our common unitholders relative to the fourth quarter of 2012. During that period, twenty-five of those quarterly increases have been 10% or greater year-over-year. In February 2013, we paid a distribution of $0.485 per unit related to the fourth quarter of 2012 representing a 10.2% increase from our distribution of $0.44 per unit related to the fourth quarter of 2011. During the fourth quarter of 2012, we paid a distribution of $0.4725 per unit related to the third quarter of 2012.

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 Net Income

Our revenues for the year ended December 31, 2012 increased $980.4 million, or 32% from 2011. Additionally, our costs and expenses increased $949.2 million or 32% 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 increase in our revenues and costs between 2012 and 2011 is primarily attributable to increased volumes from our continuing operations and our acquisitions, partially offset by slight decreases in the market prices for crude oil and petroleum products as described below.

Volumes in 2012 increased in our supply and logistics segment by 32% from 2011, as explained in our supply and logistics Segment Margin discussion below. The average closing prices for West Texas Intermediate ("WTI") crude oil on the New York Mercantile Exchange ("NYMEX") were consistent, decreasing 1% to $94.21 per barrel in 2012, as compared to $95.12 per barrel in 2011.

Table of Contents

Net income increased $45.1 million in 2012 from 2011. The increase in net income during 2012 primarily reflects improved segment margin results due to our acquisitions and increased volumes. Our income tax expense decreased due to the reversal of uncertain tax positions as a result of tax audit settlements and the expiration of statutes of limitations. These increases to net income were partially offset by increases in general and administrative expenses and interest costs.

Revenues in 2011 increased $988.3 million, or 47% from 2010. Additionally, our costs and expenses increased $878.5 million or 41% between the two periods. The significant increase in our revenues and costs between 2011 and 2010 is primarily attributable to the fluctuations in the market prices for crude oil and petroleum products. For example, prices for WTI crude oil on the NYMEX averaged $95.12 per barrel in 2011, as compared to $79.53 per barrel in 2010, or a 20% increase. Net income (attributable to us) increased $99.7 million in 2011 to $51.2 million from a net loss (attributable to us) of $48.5 million in 2010. The increase in net income during 2011 primarily reflects the non-cash charges of $76.9 million we recorded in 2010 for executive and equity-based compensation borne by our general partner. In addition, segment results for all of our segments improved during 2011 as volumes increased. Our increased segment results were partially offset by increases in depreciation and amortization expense and interest costs.

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,		
	2012	2011	2010
	(in thousands)		
Pipeline transportation	$96,539	$67,908	$48,305
Refinery services	72,883	74,618	62,923
Supply and logistics	92,911	59,975	38,336
Total Segment Margin	$262,333	$202,501	$149,564

Year Ended December 31, 2012 Compared with Year Ended December 31, 2011

Pipeline Transportation Segment

In January 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. (or “Poseidon”), 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. (or “Odyssey”). 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.

This acquisition complements our existing infrastructure in the Gulf of Mexico and enhances our ability to provide capacity and market optionality to producers for their existing and future developments as well as our refining customers onshore Texas and Louisiana. The Poseidon pipeline system is comprised of a 367-mile network of crude oil pipelines, varying in diameter from 16 to 24 inches, with capacity to deliver approximately 400,000 barrels per day of 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 of Poseidon. The Eugene Island pipeline system is primarily comprised of a 183-mile network of crude oil pipelines, the main pipeline of which is 20 inches in diameter, with capacity to deliver approximately 200,000 barrels per day of 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. An affiliate of Shell serves as the operator of Eugene Island. The Odyssey pipeline system is comprised of a 120-mile network of crude oil pipelines, varying in diameter from 12 to 20 inches, with capacity to deliver up to 200,000 barrels per day of 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 of Odyssey.

Table of Contents

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

	Year Ended December 31,	
	2012	2011
	(in thousands)	
Crude oil tariffs and revenues from direct financing leases—onshore crude oil pipelines	$31,931	$24,870
Segment margin from offshore crude oil pipelines, including pro-rata share of distributable cash from equity investees	38,500	15,772
CO_2 tariffs and revenues from direct financing leases of CO_2 pipelines	26,603	26,334
Sales of crude oil pipeline loss allowance volumes	9,165	7,756
Onshore pipeline operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	(15,607)	(12,222)
Payments received under direct financing leases not included in income	5,016	4,615
Other	931	783
Segment Margin	$96,539	$67,908
Volumetric Data (barrels/day unless otherwise noted):		
Onshore crude oil pipelines:		
Texas	51,880	45,183
Jay	22,306	16,900
Mississippi	18,711	20,629
Offshore crude oil pipelines:		
CHOPS (1)	96,664	120,723
Poseidon (1) (2)	211,375	—
Odyssey (1) (2)	36,157	—
GOPL (2)	15,191	—
CO_2 pipeline (Mcf/day):		
Free State	186,479	169,962

(1) Volumes for our equity method investees are presented on a 100% basis.
(2) Acquired in January 2012.

During 2012, crude oil volumes shipped on our Texas System and Jay System increased 6,697 barrels per day (or 15%) and 5,406 barrels per day (or 32%), respectively. Volumes on our Texas System increased primarily as a result of increased demand by one of the refiners connected to our system with capabilities for processing light crude oil such as that being produced in the Eagle Ford Shale area. Additional barrels received at our new crude-by-rail unloading terminal at Walnut Hill, Florida, increased volumes on the Jay System. On CHOPS, crude oil volumes declined 24,059 barrels per day (or 20%) during 2012 due to ongoing improvements being made by producers at several connected fields. Improvements at those fields were substantially completed late in the third quarter of 2012, and total throughput levels on the pipeline have returned to levels last seen in the first quarter of 2011.

We deliver CO_2 on our Free State Pipeline for use in tertiary recovery operations in east Mississippi. Denbury currently has rights to exclusive use of the pipeline and is required to use the pipeline to supply CO_2 to its current and certain of its other tertiary operations in east Mississippi. We have a twenty-year financing lease (through 2028) with Denbury for their use of our NEJD System. Denbury makes fixed quarterly base rent payments to us of $5.2 million per quarter or approximately $20.7 million per year.

Segment Margin for our pipeline transportation segment increased $28.6 million, or 42%, in 2012 as compared to 2011. The significant components of this change were as follows:

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Crude oil tariff revenues of onshore crude oil pipelines increased $7.1 million primarily due to upward tariff indexing of 6.9% and 8.6% for our FERC-regulated pipelines effective in July 2011 and 2012, respectively, and increased volumes of 10,185 barrels per day transported on our onshore crude oil pipelines as described above.

Table of Contents

- Segment margin from our offshore crude oil pipelines increased $22.7 million reflecting a contribution of $29.1 million from our interests in the Gulf of Mexico pipelines that we acquired in 2012. The contribution to Segment Margin by CHOPS declined by $6.4 million from 2011 due to ongoing improvements being made by producers at several connected fields as discussed above.
- Revenues from sales of pipeline loss allowance volumes improved Segment Margin by $1.4 million due to an increase of approximately 10,200 barrels sold in 2012 compared to 2011.
- Pipeline operating costs, excluding non-cash charges, increased $3.4 million, due to pipeline integrity maintenance on the pipelines and employee compensation and related benefit costs.

Refinery Services Segment

Operating results for our refinery services segment were as follows:

	Year Ended December 31,	
	2012	2011
Volumes sold (in Dry short tons "DST"):		
NaHS volumes	142,712	147,670
NaOH (caustic soda) volumes	77,492	99,702
Total	220,204	247,372
Revenues (in thousands):		
NaHS revenues	$153,689	$152,422
NaOH (caustic soda) revenues	44,322	47,339
Other revenues	7,099	10,633
Total external segment revenues	$205,110	$210,394
Segment Margin (in thousands)	$72,883	$74,618
Average index price for NaOH per DST [1]	$575	$513
Raw material and processing costs as % of segment revenues	48 %	48 %

(1) Source: IHS Chemical

Refinery services Segment Margin for 2012 decreased $1.7 million, or 2%, from 2011. The significant components of this fluctuation were as follows:

- NaHS sales volumes during 2012 decreased 3% from 2011 primarily due to the timing of sales to South American customers. In late 2011, we experienced a high volume of sales to these customers. Sales volumes to customers in South America can fluctuate due to scheduling of shipments.
- NaHS revenues increased primarily as a function of the increase in the average index price for caustic soda. 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 increased correspondingly to the rise in the average index price for caustic soda. In addition, in the first half of 2012, longer than anticipated refinery turnarounds at some of our largest refinery service locations resulted in increased costs as a result of processing at and shipping from less efficient locations to ensure uninterrupted supplies of NaHS to our customers.
- Caustic soda sales volumes decreased 22% primarily due to turnarounds at some of our refinery customers in the first half of 2012. 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.

Table of Contents

- Average index prices for caustic soda increased to $575 per DST during 2012 compared to $513 per DST during 2011. 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.

Supply and Logistics Segment

Our supply and logistics segment is focused on utilizing our knowledge of the crude oil and petroleum markets and our logistics capabilities from our terminals, railcars, rail loading and unloading facilities, trucks and barges to provide suppliers and customers with a full suite of services. These services include:

- purchasing 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;
- 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;
- utilizing our fleet of trucks and trailers, railcars, and barges to take advantage of logistical opportunities primarily in the Gulf Coast states and inland waterways; 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 contain 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. The opportunities to provide this service cannot be predicted, but their contribution to margin as a percentage of their revenues tend to be higher than the same percentage attributable to our recurring operations.

We utilize our fleet of 300 trucks, 350 trailers, 180 rail cars, 50 barges, 22 push/tow boats, and 1.7 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.

Table of Contents

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

	Year Ended December 31,	
	2012	2011
	(in thousands)	
Supply and logistics revenue	$3,797,750	$2,825,768
Crude oil and products costs, excluding unrealized gains and losses from derivative transactions	(3,541,562)	(2,642,964)
Operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	(163,489)	(122,925)
Other	212	96
Segment Margin	$92,911	$59,975
Volumes of crude oil and petroleum products (barrels per day)	94,043	71,043

As discussed above in "Revenues, Costs and Expenses and Net Income," the average market prices of crude oil and petroleum products were consistent between 2012 and 2011. Fluctuations in these prices, however, have a limited impact on our Segment Margin.

Segment Margin for our supply and logistics segment increased $32.9 million, or 55%, in 2012 as compared to 2011. The increase in Segment Margin resulted primarily from the contribution of the black oil barge transportation assets that we acquired in August 2011 and February 2012 and increased volumes handled by our expanded trucking, rail and barge fleets. Our total volumes of crude oil and petroleum products increased by 32% primarily as a result of these expansions. Our operating costs, excluding non-cash charges, increased 33% between the two periods due to our expanded trucking, rail and barge fleets and increased utilization of such fleets.

Other Costs and Interest

General and administrative expenses

	Year Ended December 31,	
	2012	2011
	(in thousands)	
General and administrative expenses not separately identified below:		
Corporate	$22,873	$19,466
Segment	11,735	8,868
Equity-based compensation plan expense	6,132	1,763
Third party costs related to business development activities and growth projects	1,679	4,376
Total general and administrative expenses	$42,419	$34,473

Routine corporate and segment general and administrative expenses increased between 2012 and 2011 as a result of salary and benefits expenses associated with increases in personnel to support our growth. Additionally, increases in the market price of our common units and an increase in the number of awards outstanding due to increases in personnel affected expense related to our equity-based compensation plans. A decrease in third party costs related to business and growth transactions resulted in a decrease of approximately $2.7 million between the periods.

Table of Contents

Depreciation and amortization expense

	Year Ended December 31,	
	2012	2011
	(in thousands)	
Depreciation on fixed assets	$37,398	$27,544
Amortization of intangible assets	19,930	30,952
Amortization of CO_2 volumetric production payments	3,838	3,694
Total depreciation and amortization expense	$61,166	$62,190

Depreciation and amortization expense decreased $1 million between 2012 and 2011 primarily as a result of decreases in amortization of intangible assets, offset by an increase in depreciation expense. Amortization of intangible assets decreased $11 million as we amortize our intangible assets over the period in which we expect them to contribute to our future cash flows. Generally, the amortization we record on those assets is greater in the initial years following their acquisition because our intangible assets are generally more valuable in the first years after an acquisition. Depreciation expense increased $9.9 million primarily as a result of our recent acquisitions, including the black oil barge transportation assets in August 2011 and February 2012.

Interest expense, net

	Year Ended December 31,	
	2012	2011
	(in thousands)	
Interest expense, senior secured credit facility (including commitment fees)	$14,212	$12,986
Interest expense, senior unsecured notes	26,578	19,961
Amortization and write-off of debt issuance costs and premium	4,037	2,940
Capitalized interest	(3,891)	(106)
Interest income	(15)	(14)
Net interest expense	$40,921	$35,767

Net interest expense increased $5.2 million during 2012, primarily as a result of increased borrowings associated with acquisitions. Interest expense on our senior unsecured notes increased $6.6 million over the same period as a result of issuing an additional $100 million of senior unsecured notes under the indenture in February 2012 to repay borrowings under our credit facility. An increase in capitalized interest costs of $3.8 million attributable to our growth capital expenditures and investments in the SEKCO pipeline joint venture (see below for more information) partially offset the increase in interest expense.

Table of Contents

Year Ended December 31, 2011 Compared with Year Ended December 31, 2010

Pipeline Transportation Segment

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

	Year Ended December 31,	
	2011	2010
	(in thousands)	
Crude oil tariffs and revenues from direct financing leases—onshore crude oil pipelines	$24,870	$20,351
Segment margin from offshore crude oil pipelines, including pro-rata share of distributable cash from equity investees	15,772	2,185
CO_2 tariffs and revenues from direct financing leases of CO_2 pipelines	26,334	26,413
Sales of crude oil pipeline loss allowance volumes	7,756	5,519
Onshore pipeline operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	(12,222)	(11,323)
Payments received under direct financing leases not included in income	4,615	4,202
Other	783	958
Segment Margin	$67,908	$48,305
Volumetric Data (barrels/day unless otherwise noted):		
Onshore crude oil pipelines:		
Texas	45,183	28,748
Jay	16,900	15,646
Mississippi	20,629	23,537
Offshore crude oil pipelines:		
CHOPS (1) (2)	120,723	149,270
CO_2 pipeline (Mcf/day):		
Free State	169,962	167,619

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

(2) 2010 volumes for CHOPS represent the daily average since our acquisition date in November 2010.

During 2011, crude oil volumes shipped on our Texas System increased 16,435 barrels per day (or 57%) primarily as a result of increased demand by one of the refiners connected to our system with capabilities for processing light crude oil such as that being produced in the Eagle Ford Shale area. On CHOPS, crude oil volumes declined 28,547 barrels per day (or 19%) during 2011 due to planned improvements to offshore field facilities by producers with fields connected to CHOPS that were performed in the last three quarters of 2011. These field improvements by the producers are expected to increase volumes on CHOPS in the future.

Pipeline transportation Segment Margin increased $19.6 million in 2011 as compared to 2010. The primary factors in this increase are summarized below.

- Segment margin from our offshore crude oil pipeline, CHOPS, increased $13.6 million during 2011 as a result of owning our 50% interest for a full year in 2011. Despite the increase, planned improvements by producers of offshore field facilities from the second quarter of 2011 through the fourth quarter of 2011 negatively impacted our revenue generating volumes during the year.
- Crude oil tariff revenues of onshore crude oil pipelines increased $4.5 million reflecting increased volumes of 14,781 barrels per day transported on our onshore crude oil pipelines as described above.
- An increase in revenues from sales of pipeline loss allowance volumes increased Segment Margin by $2.2 million related to the significant increase (an average of $16 per barrel) in crude oil prices.
- Pipeline operating costs, excluding non-cash charges increased $0.9 million, primarily due to increased employee compensation and related benefit costs.

44

Table of Contents

Refinery Services Segment

Operating results for our refinery services segment were as follows:

	Year Ended December 31,	
	2011	2010
Volumes sold (in DST):		
NaHS volumes	147,670	145,213
NaOH (caustic soda) volumes	99,702	93,283
Total	247,372	238,496
Revenues (in thousands):		
NaHS revenues	$152,422	$119,688
NaOH (caustic soda) revenues	47,339	29,578
Other revenues	10,633	9,190
Total external segment revenues	$210,394	$158,456
Segment Margin (in thousands)	$74,618	$62,923
Average index price for NaOH per DST [(1)]	$513	$353
Raw material and processing costs as % of segment revenues	48 %	37 %

(1) Source: IHS Chemical

Refinery services Segment Margin for the year ended 2011 increased $11.7 million, or 19%, from 2010. The significant components of this change were as follows:

- Revenues increased primarily as a function of the increase in the average index price for caustic soda. Average index prices of caustic soda increased to an average of $513 per DST during 2011 as compared to $353 per DST in 2010. Those price movements affect the revenues and costs related to our sulfur removal services as well as our caustic soda sales activities. However, changes in caustic soda prices do not materially affect Segment Margin attributable to our sulfur processing services because we generally pass those costs through to our NaHS sales customers. Additionally, our bulk purchase and storage capabilities related to caustic soda allow us to mitigate the effects of changes in index prices for caustic on our operating costs.
- 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 increased correspondingly to the rise in the average index price for caustic soda, although operating efficiencies at several of our sour gas processing facilities as well as our favorable management of the acquisition and utilization of caustic soda in our operations and our logistics management, as discussed below, helped offset these costs.
- NaHS sales volumes during 2011 increased 2% from 2010. Although there were decreased levels of activity by our pulp and paper customers, the return of industrialization and urbanization in the world’s emerging economies increased the demand for products requiring copper and molybdenum. These trends led to a noticeable increase in NaHS demand from our mining customers primarily in North America in 2011 as compared to 2010.
- Caustic soda sales volumes increased 7%. 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 caustic soda for re-sale to third parties.

Table of Contents

Supply and Logistics Segment

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

	Year Ended December 31, 2011	2010
	(in thousands)	
Supply and logistics revenue	$2,825,768	$1,894,612
Crude oil and products costs, excluding unrealized gains and losses from derivative transactions	(2,642,964)	(1,761,161)
Operating costs, excluding non-cash charges for equity-based compensation and other non-cash expenses	(122,925)	(95,011)
Other	96	(104)
Segment Margin	$59,975	$38,336
Volumes of crude oil and petroleum products (barrels per day)	71,043	61,012

As discussed above in “Revenues, Costs and Expenses and Net Income,” the average market prices of crude oil increased by approximately $16 per barrel, or approximately 20% between the two periods. Similarly, market prices for petroleum products increased significantly between 2011 and 2010. Fluctuations in these prices, however, have a limited impact on our Segment Margin. The increase in Segment Margin during 2011 versus 2010 resulted primarily from several factors, including:

- increased volumes of approximately 16% from 2010 primarily due to a greater availability of volumes of crude oil and heavy-end petroleum products resulting from increased refinery utilization in our operating area;
- increased production from new sources of crude oil, principally shale oil production, increased demand for our services;
- higher foreign demand for fuel oil and other heavy-end petroleum products helped sustain the price environment for the products we sell;
- operating efficiencies and modifications to our existing crude oil and petroleum products commercial arrangements; and
- the contribution from the additional black oil barges we acquired in August 2011.

Other Costs and Interest

General and administrative expenses

	Year Ended December 31, 2011	2010
	(in thousands)	
General and administrative expenses not separately identified below:		
Corporate	$19,466	$17,276
Segment	8,868	8,200
Equity-based compensation plan expense	1,763	1,955
Third party costs related to IDR Restructuring, business development activities and growth projects	4,376	7,290
Expenses related to change in owner of our general partner	—	1,762
Non-cash compensation expense related to management team	—	76,923
Total general and administrative expenses	$34,473	$113,406

General and administrative expenses decreased $78.9 million in 2011 from 2010 primarily due to non-cash compensation charges of $76.9 million in the prior year related to equity-based compensation arrangements between executive management and our general partner. The decrease in general and administrative expenses was partially offset primarily by an increase in personnel resulting in greater salaries and benefits expenses.

Table of Contents

The non-cash compensation charges recorded in 2010 reflect the exchange of certain equity interests in our general partner held by our executives for new common units (including waiver units). These charges were incurred in connection with our IDR Restructuring. Although the compensation under these arrangements ultimately came from our general partner, we recorded the fair value of the related compensation expense in our Consolidated Statements of Operations in general and administrative expenses. See Note 15 to our Consolidated Financial Statements in Item 8 for more information concerning the non-cash compensation costs incurred in connection with our IDR Restructuring.

Depreciation and amortization expense

	Year Ended December 31,	
	2011	2010
	(in thousands)	
Depreciation on fixed assets	$27,544	$22,510
Amortization of intangible assets	30,952	26,805
Amortization of CO_2 volumetric production payments	3,694	4,254
Total depreciation and amortization expense	$62,190	$53,569

Depreciation and amortization expense increased $8.6 million between 2011 and 2010 primarily as a result of an adjustment in the useful lives of certain of our intangible assets in the first quarter of 2011 and depreciation expense related to our black oil barge assets acquisition. In the first quarter of 2011, we adjusted the useful lives of our supply and logistics trade names, which resulted in an increase of amortization expense of $7.7 million during the year. The impact of this change is not expected to be material in future periods.

Interest expense, net

	Year Ended December 31,	
	2011	2010
	(in thousands)	
Genesis Facility and Notes:		
Interest expense, credit facility (including commitment fees)	$12,986	$10,624
Interest expense, senior unsecured notes	19,961	2,406
Amortization of credit facility and notes issuance costs	2,940	1,551
Bridge financing fees	—	3,219
Write-off of facility fees	—	402
DG Marine Facility:		
Interest expense and commitment fees	—	2,512
Interest rate swaps settlement	—	1,553
Write-off of facility fees	—	794
Capitalized interest	(106)	(84)
Interest income	(14)	(53)
Net interest expense	$35,767	$22,924

Net interest expense increased $12.8 million during 2011, primarily reflecting increased interest expense on our senior unsecured notes, which were outstanding for an entire year during 2011. Interest expense on our credit facility also increased during 2011 as our average debt balance increased $8.1 million. The increase in the average outstanding balance under our credit facility is attributable primarily to growth initiative projects during 2011, including expansion of our Texas pipeline infrastructure and the acquisition of the Wyoming refinery and pipeline assets. The increase in net interest expense during 2011 was partially offset by the repayment of the DG Marine credit facility in July 2010.

Table of Contents

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 2012 and 2011, we recorded an income tax benefit of $9.2 million and $1.2 million, respectively. In 2010, we recorded income tax expense of $2.6 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. The benefit during 2011 reflects a net loss for those wholly-owned corporate subsidiaries that are taxable as corporations.

Financial Measures

Segment Margin

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 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 before income taxes is included in our segment disclosures in Note 12 to our Consolidated Financial Statements in Item 8.

Available Cash before Reserves

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 accounting principles generally accepted in the U.S., also referred to as GAAP. The accompanying schedule below provides a reconciliation of this non-GAAP financial measure to its most directly comparable GAAP financial measure. 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.

Available Cash before Reserves, also referred to as distributable cash flow, 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 assess: (1) the financial performance of our assets without regard to financing methods, capital structures, or historical cost basis; (2) the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness; (3) our operating performance and return on capital as compared to those of other companies in the midstream energy industry, without regard to financing and capital structure; and (4) the viability of projects and the overall rates of return on alternative investment opportunities. Because Available Cash before Reserves excludes some items that affect net income or loss and because these measures may vary among other companies, the Available Cash before Reserves data presented in this Annual Report on Form 10-K may not be comparable to similarly titled measures of other companies.

Available Cash before Reserves is a performance measure used by our management to compare cash flows generated by us to the cash distribution paid to our common unitholders. This is an important financial measure to our public unitholders since it is an indicator of our ability to provide a cash return on their investments. Specifically, this financial measure aids investors in determining whether or not we are generating cash flows at a level that can support a quarterly cash distribution to the partners. Lastly, Available Cash before Reserves is the quantitative standard used throughout the investment community with respect to publicly-traded partnerships.

Available Cash before Reserves is net income as adjusted for specific items, the most significant of which are the addition of 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) and 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, the subtraction of maintenance capital expenditures, which are expenditures that are necessary to sustain existing (but not to provide new sources of) cash flows, and the elimination of earnings of DG Marine in excess of distributable cash until July 2010 when DG Marine's credit facility was repaid.

Table of Contents

Available Cash before Reserves for the years ended December 31, 2012, 2011 and 2010 was as follows:

	Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
Net income (loss) attributable to Genesis Energy, L.P.	$96,319	$51,249	$(48,459)
Depreciation and amortization	61,166	62,190	53,569
Cash received from direct financing leases not included in income	5,016	4,615	4,203
Cash effects of sales of certain assets	773	6,424	1,146
Effects of distributable cash generated by equity method investees not included in income	24,464	16,681	2,284
Cash effects of equity-based compensation plans	(3,280)	(2,394)	(1,349)
Non-cash equity-based compensation expense	4,978	311	82,979
Expenses related to acquiring or constructing assets that provide new sources of cash flow	1,679	4,376	11,260
Unrealized loss on derivative transactions excluding fair value hedges	86	724	59
Maintenance capital expenditures	(4,430)	(4,237)	(2,856)
Non-cash tax (benefit) expense	(9,222)	(2,075)	1,337
Earnings of DG Marine in excess of distributable cash	—	—	(848)
Other items, net	1,609	335	(1,826)
Available Cash before Reserves	$179,158	$138,199	$101,499

Liquidity and Capital Resources

General

As of December 31, 2012, we believe our balance sheet and liquidity position remained strong. We had $483.3 million of borrowing capacity available under our $1 billion senior secured revolving credit facility. As discussed in "Subsequent Events Affecting Liquidity and Capital Resources" below, in February 2013, we issued an additional $350 million in aggregate principal amount senior unsecured notes. The net proceeds were used to repay borrowings under our credit facility and for general partnership purposes. We anticipate that our future internally-generated funds and the funds available under our credit facility will allow us to meet our day-to-day capital needs, excluding, for example, major capital expenditures and/or refinancings. Our primary sources of liquidity have been cash flows from operations, debt offerings and borrowing availability under our credit facility.

Our primary cash requirements consist of:

- Working capital, primarily inventories;
- Routine operating expenses;
- Capital expansion 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 July 2012, we amended and restated our senior secured credit facility with a syndicate of banks to, among other things, increase the committed amount from $775 million to $1 billion and the accordion feature from $225 million to $300

million, giving us the ability to expand the size of the facility up to an aggregate of $1.3 billion for acquisitions or internal growth projects, subject to lender consent. The inventory financing sublimit tranche was increased from $125 million to $150 million, and the term of our credit facility was extended to July 25, 2017. This inventory tranche 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.

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 applicable margin varies from 1.75% to 2.75% on eurodollar borrowings and from 0.75% to 1.75% on alternate base rate borrowings.
- Letter of credit fees range from 1.75% to 2.75%.
- The commitment fee on the unused committed amount will range from 0.375% to 0.50%.

We do not anticipate any of the lenders that participate in our credit facility being unable to satisfy their obligations under the credit facility.

In February 2012, we issued an additional $100 million of aggregate principal amount of senior unsecured notes under our existing 7.875% senior notes indenture for which the net proceeds were used to repay borrowings under our credit facility. The notes were issued at 101% of face value at an effective interest rate of 7.682%. The notes mature on December 15, 2018. See Note 10 to our Consolidated Financial Statements in Item 8 for more information.

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. See Note 11 to our Consolidated Financial Statements in Item 8 for more information.

At December 31, 2012, long-term debt totaled $850.9 million, consisting of $500 million outstanding under our credit facility (including $63.9 million borrowed under the inventory sublimit tranche) and $350.9 million of senior unsecured notes due in 2018.

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

Subsequent Events Affecting Liquidity and Capital Resources

On February 8, 2013, we issued an additional $350 million in aggregate principal amount of 5.75% senior unsecured notes. The notes mature on February 15, 2021. The net proceeds were used to repay borrowings under our credit facility and for general partnership purposes.

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. However, when the crude oil markets are in contango, we may store crude for future delivery utilizing futures contracts to hedge our risk to fluctuations in prices.

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 pay from cash on hand) to pay for the oil or products, which negatively impacts 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 oil or products. Additionally, we may be required to deposit margin funds with the NYMEX when prices increase as the value of the

Table of Contents

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 $189.3 million and $58.3 million for 2012 and 2011, 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 operating cash 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 2012 compared to 2011 was primarily due to higher cash earnings and decreases 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 smaller internal growth projects and distributions primarily with cash generated by our operations. Acquisition activities and large internal growth projects have historically been funded with borrowings under our credit facility, equity issuances and 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,		
	2012	2011	2010
		(in thousands)	
Capital expenditures for fixed and intangible assets:			
Maintenance capital expenditures:			
Pipeline transportation assets	$376	$247	$522
Refinery services assets	1,183	1,200	1,433
Supply and logistics assets	2,871	2,790	901
Total maintenance capital expenditures	4,430	4,237	2,856
Growth capital expenditures:			
Pipeline transportation assets	59,009	7,382	573
Refinery services assets	1,509	646	—
Supply and logistics assets (1)	92,025	11,056	839
Information technology systems upgrade projects	1,631	4,128	10,613
Total growth capital expenditures	154,174	23,212	12,025
Total maintenance and growth capital expenditures	158,604	27,449	14,881
Capital expenditures for business combinations, net of liabilities assumed:			
Offshore pipelines (2)	205,576	194	332,462
Acquisition of FMT assets	—	143,479	—
Wyoming refinery and related pipeline	—	20,000	—
Total business combinations capital expenditures	205,576	163,673	332,462
Capital expenditures related to equity investees (3)	63,749	—	—
Total capital expenditures	$427,929	$191,122	$347,343

(1) In 2012, amount includes the purchase of barge assets for $30.9 million (see below for more information).

(2) In 2012, amount represents the investment to acquire from Marathon Oil Company interests in several Gulf of Mexico crude oil pipeline systems. In 2011 and 2010, amounts represent the investment to acquire our interest in CHOPS.

(3) 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.

Table of Contents

Acquisitions

We continue to pursue a growth strategy that requires significant capital. In January 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. (or "Poseidon"), 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. (or "Odyssey"). 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.

See Note 3 to our Consolidated Financial Statements in Item 8 for further information related to the acquisitions.

Growth Capital Expenditures

Total capital expenditures on projects currently under construction, and disclosed in the following discussion, are estimated to be approximately $475 million, inclusive of capital expenditures incurred in prior quarters. We anticipate that approximately $305 million of that total will be spent in 2013.

Gulf Coast Infrastructure

We plan to invest approximately $125 million to improve existing assets and develop 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, constructing a new 18-mile 20-inch diameter crude oil pipeline connecting Port Hudson to the Baton Rouge Maryland Terminal and continuing downstream to the Anchorage Tank Farm and building a new crude oil unit train facility at the Maryland Terminal. The Port Hudson upgrades and new crude oil pipeline are expected to be completed by the end of 2013 and the Maryland Terminal completion is scheduled for the second quarter of 2014.

Texas City Projects

In the fourth quarter of 2012, we completed two projects to increase the services we provide to producers and refiners. We acquired three above-ground storage tanks located in Texas City, Texas and an existing barge dock at the same location, all approximately 1.5 miles from our existing Texas pipeline system. We also constructed a truck station and tankage in West Columbia, Texas to provide incremental transportation service for the Eagle Ford Shale and other Texas production through our pipeline system to refining markets in the greater Houston/Texas City area. We are able to handle approximately 40,000 barrels per day of crude oil through the Texas City terminal. In addition, we have initiated construction of a 18-inch diameter loop of our existing crude oil pipeline into Texas City, supported by a term contract with one of our refining customers, which we expect will allow us to significantly expand our total service capabilities into the Texas City area by the late second quarter or early third quarter of 2013.

HollyFrontier Tulsa Project

We are installing a new sour gas processing facility at Holly Refining and Marketing's refinery complex located in Tulsa, Oklahoma. The new facility, expected to be completed in mid-2013, will remove a portion of the sulfur from the crude oil refined at Holly's complex and is expected to result in potential additional capacity of 24,000 DST per year of NaHS.

Rail Projects

In August 2012, we completed construction on the first phase of a new crude-by-rail unloading terminal connected to our existing crude oil pipeline at Walnut Hill, Florida. This facility is capable of handling unit train shipments of oil for direct deliveries to an existing refinery customer and indirect deliveries (through third-party common carriers) to multiple other markets in the Southeast at the option of the shippers. We anticipate the second phase of the terminal, which includes a 100,000 barrel storage tank and related equipment, will be fully operational in the first quarter of 2013.

In 2012, we completed initial phase construction of a crude oil rail loading facility in Wink, Texas, giving us the capability to load Genesis and third party railcars designed to move West Texas production to more highly valued markets. Additional expansion of this facility, which we estimate will be completed by late third quarter or early fourth quarter of 2013, will allow us to increase the capacity of this system.

In 2012, we commenced construction on a crude oil rail unloading/loading facility at our existing terminal located in Natchez, Mississippi, which is designed to facilitate the movement of Canadian bitumen/dilbit to Gulf Coast markets. The facility will have the capability to unload bitumen/dilbit as well as loading diluent for backhauls to Canada. We estimate this facility will be operational in the first quarter of 2013.

Table of Contents

Wyoming Gathering Project
We are re-activating portions of the related gathering and transportation pipelines in Wyoming and constructing a new pipeline which will connect to the Casper, Wyoming markets. We anticipate the re-activation of existing pipelines and the new pipeline will be completed in the second quarter of 2013.
Purchase of FMT Barges
In February 2012, we purchased seven barges from Florida Marine Transporters, which previously had been subleased to us in connection with the acquisition of the black oil barge assets in August 2011. The cost of the seven barges totaled $30.9 million, which was funded with borrowing under our credit facility.
Capital Expenditures Related to Equity Investees
SEKCO, a joint venture with Enterprise Products, is constructing a deepwater pipeline serving the Lucius development area in southern Keathley Canyon of the Gulf of Mexico. The new pipeline is expected to begin service by mid-2014. We expect to spend approximately $200 million for our share of the pipeline construction through 2014 and to reimburse Enterprise Products for our portion of previously incurred costs. In 2012, we contributed $63.7 million to SEKCO that was used to fund our share of the construction costs incurred during the year. Approximately $125 million of the total estimate is expected to be paid in 2013. Most cost overruns and other costs incurred associated with weather related delays will be the responsibility of the producers that have entered into transportation agreements with us.
Maintenance Capital Expenditures
Maintenance capital expenditures for 2013 are anticipated to total approximately $4 million to $5 million. We would expect to spend similar amounts annually on maintenance capital projects in future years.
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 quarters, including the distribution paid for the fourth quarter of 2012, 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
2010			
4th Quarter	February 14, 2011	$0.4000	$25,846
2011			
1st Quarter	May 13, 2011	$0.4075	$26,343
2nd Quarter	August 12, 2011	$0.4150	$29,878
3rd Quarter	November 14, 2011	$0.4275	$30,777
4th Quarter	February 14, 2012	$0.4400	$31,677
2012			
1st Quarter	May 15, 2012	$0.4500	$35,768
2nd Quarter	August 14, 2012	$0.4600	$36,563
3rd Quarter	November 14, 2012	$0.4725	$38,375
4th Quarter	February 14, 2013 (1)	$0.4850	$39,390

(1) This distribution was paid on February 14, 2013 to unitholders of record as of February 1, 2013.

Table of Contents

Commitments and Off-Balance Sheet Arrangements

Contractual Obligations and Commercial Commitments

In addition to our credit facility discussed above, we have contractual obligations under operating leases as well as commitments to purchase crude oil and petroleum products. The table below summarizes our obligations and commitments at December 31, 2012.

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)	$—	$—	$500,000	$350,895	$850,895
Estimated interest payable on long-term debt (2)	48,813	97,625	88,502	26,581	261,521
Operating lease obligations (3)	19,285	37,257	21,674	43,145	121,361
Unconditional purchase obligations (4)	297,418	—	—	—	297,418
Other Cash Commitments:					
Asset retirement obligations (5)	—	—	—	31,038	31,038
Total	$365,516	$134,882	$610,176	$451,659	$1,562,233

(1) Our credit facility allows us to repay and re-borrow funds at any time through the maturity date of July 25, 2017. Our senior unsecured notes are due December 15, 2018. In February 2013, we issued an additional $350 million in aggregate principal amount senior unsecured notes that mature in February 2021. The net proceeds were used for general partnership purposes, including to repay borrowings under our credit facility, which will result in extending the repayment of approximately $350 million of our long term debt obligations as of February 2013 from the 3 to 5 year payment period to the more than 5 year payment period.

(2) Interest on our long-term debt under our credit facility is at market-based rates. The interest rate on our senior unsecured notes is 7.875%. The amount shown for interest payments represents the amount that would be paid if the debt outstanding at December 31, 2012 under our credit facility remained outstanding through the final maturity date of July 25, 2017 and interest rates remained at the December 31, 2012 market levels through the final maturity date. Also included is the interest on our senior unsecured notes through the maturity date.

(3) Includes operating lease obligations on approximately 400 rail cars which we expect to receive in 2013.

(4) 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, 2012 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.

(5) Represents the estimated future asset retirement obligations on an undiscounted basis. The recorded asset retirement obligation on our balance sheet at December 31, 2012 was $12.7 million and is further discussed in Note 6 to our Consolidated Financial Statements.

In connection with our 50% interest in SEKCO as described above we have committed to share the required funding with Enterprise Products to construct a deepwater pipeline serving the Lucius development area in southern Keathley Canyon of the Gulf of Mexico. We expect to spend approximately $200 million for our share of the pipeline construction through 2014 and to reimburse Enterprise Products for our portion of previously incurred costs. In 2012, we paid $63.7 million. Approximately $125 million of the total estimate is expected to be paid in 2013. Most cost overruns and other costs incurred associated with weather related delays will be the responsibility of the producers

that have entered into transportation agreements with us. See “Significant Events” above for more information.
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.

Table of Contents

Critical Accounting Policies and Estimates

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

We have defined critical accounting policies and estimates as those that are most important to the portrayal of our financial results and positions. These policies require management's judgment and often employ the use of information that is inherently uncertain. Our most critical accounting policies pertain to measurement of the fair value of assets and liabilities in business acquisitions, depreciation, amortization and impairment of long-lived assets, 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 and intangible assets with indefinite lives are not amortized but instead are 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.

Table of Contents

During 2011, we adopted new accounting guidance, which provides the option to make a qualitative evaluation about the likelihood of goodwill impairment. After performing a qualitative assessment of relevant events and circumstances, 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 quarterly basis to determine if there is an indicator of impairment. As of December 31, 2012, 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, 2012. We did not have any goodwill impairments in 2012, 2011 or 2010.

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

Equity Compensation Plan Accruals

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, 2012, we had 354,713 phantom units outstanding and recorded $6.7 million of expense during 2012. 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, 2012, we estimated approximately $7.5 million of compensation costs to be recognized over a weighted average period of approximately two years for these awards. Changes in our assumptions may impact our liabilities and expenses related to these awards.

We accrue for the fair value of our liability for the stock appreciation rights, or SAR, awards we have issued to our employees and directors. Under our SAR plan, grantees receive cash for the difference between the market value of our common units and the strike price of the award at the time of exercise. We estimate the fair value of SAR awards at each balance sheet date using the Black-Scholes option pricing model. The Black-Scholes valuation model requires the input of somewhat subjective assumptions, including expected stock price volatility and expected term. Other assumptions required for estimating fair value with the Black-Scholes model are the expected risk-free interest rate and our expected distribution yield. The risk-free interest rates used are the U.S. Treasury yield for bonds matching the expected term of the option on the date of grant. We recognize the equity-based compensation expense on a straight-line basis over the requisite service period for the awards. The expense we recognize is net of estimated forfeitures. We estimate our forfeiture rate at each balance sheet date based on prior experience. As of December 31, 2012, there was less than $0.1 million of total compensation cost to be recognized in future periods related to non-vested SARs. The cost is expected to be recognized in the first quarter of 2013. We also record compensation cost for changes in the estimated liability for vested SARs. The liability recorded for vested SARs fluctuates with the market price of our common units. 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, 2012, 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

Recent and Proposed Accounting Pronouncements

Recently Issued

In July 2012, the Financial Accounting Standards Board ("FASB") issued guidance intended to simplify the impairment test for indefinite-lived intangible assets other than goodwill by giving entities the option to first assess qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired. The results of the qualitative assessment would be used as a basis in determining whether it is necessary to perform the two-step quantitative impairment testing. An entity can choose to perform the qualitative assessment on none, some or all of its indefinite-lived intangible assets, or may bypass the qualitative assessment and proceed directly to the quantitative impairment test. This guidance will be effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012, with early adoption permitted in certain circumstances. We will adopt this guidance on January 1, 2013. Our adoption is not expected to have a material impact on our financial position, results of operations or cash flows.

Recently Adopted

In December 2011, the FASB issued guidance requiring new disclosures for financial instruments and derivative instruments that are eligible for offset in the statement of financial position or subject to a master netting arrangement. The new guidance is effective for us beginning January 1, 2013 and is not expected to have a significant impact on our financial position, results of operations or cash flows.

In June 2011, the FASB issued guidance that modified how comprehensive income is presented in an entity’s financial statements. The guidance issued requires an entity to present the total comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements and eliminates the option to present the components of other comprehensive income as part of the statement of equity. We adopted the revised financial statement presentation for comprehensive income beginning January 1, 2012 and it did not have a significant impact on our financial position, results of operations or cash flows. The guidance pertaining to reclassifying items out of accumulated other comprehensive income has been deferred and will be effective for us beginning January 1, 2013. The adoption of this guidance is not expected to have a significant impact on our financial position, results of operations or cash flows.

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, 2012 were categorized as non-trading. On December 31, 2012 we had entered into NYMEX future contracts that will settle between January and March 2013 and NYMEX options contracts that will settle during February and April 2013. 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, 2012. 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

Table of Contents

open positions are presented below. Fair values were determined by using the notional amount in barrels or gallons multiplied by the December 31, 2012 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	316	Bbl		$91.82	$27,919	$1,096	$29,015
Heating Oil	Bbl	62	Gal	(1)	$3.03	$7,864	$30	$7,894
#6 Fuel Oil	Bbl	765	Bbl		$94.65	$70,666	$1,741	$72,407
Buy (Long) Contracts:								
Crude Oil	Bbl	199	Bbl		$91.84	$17,842	$434	$18,276
#6 Fuel Oil	Bbl	160	Bbl		$94.65	$14,890	$255	$15,145
NYMEX Option Contracts (2)								
Written Contracts:								
Crude Oil	Bbl	325	Bbl		$1.24	$523	$(121)	$402
Purchased Contracts:								
Crude Oil	Bbl	85	Bbl		$0.58	$46	$3	$49
NYMEX Swap Contracts								
Crude Oil	Bbl	100	Bbl		$17.94	$1,725	$69	$1,794

(1) Prices and volumes are 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, 2012, we had $500 million of debt outstanding under our credit facility. For the year ended December 31, 2012, a 10% change in LIBOR would have resulted in approximately a $1.2 million change in net income.

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

58

Table of Contents

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, 2012. 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. Based on our assessment, we believe that, as of December 31, 2012, 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, 2012. 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.

As is common with MLPs, our partnership structure does not allow our unitholders (of our Class A and Class B Common Units and Waiver Units) to directly or indirectly participate in our management or operations. The board of directors of our general partner must approve significant matters (such as business strategies, mergers, business combinations, acquisitions or dispositions of significant assets, issuances of common units, incurrence of debt or other financing and the payment of distributions.) The holders of our Waiver Units are not, generally, entitled to vote on any matters. The holders of 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 the removal of our general partner (or the director election rights of our Class B Common Unitholders) under specified circumstances. For example, our unitholders may remove our general partner by a vote of the holders of not less than a majority of the outstanding common units, excluding units held by our general partner and its affiliates. Any removal of our general partner is also subject to the approval of a successor general partner by the vote of the holders of a majority of the outstanding common units.

Collectively, members of the Davison family own approximately 17% of our Class A Common Units and 76.9% of our Class B 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., Donald L. Evans, Corbin J. Robertson III, Kenneth M. Jastrow II, and Mr. Sims. Our board of directors has determined that each of Ms. Gasaway and Messrs. Evans, Robertson and Jastrow 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 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.

Risk Oversight

We face a number of risks, including environmental and regulatory risks, and others, such as the impact of competition and weather conditions. 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

Table of Contents

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 compensation 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 buying, selling or engaging in transactions with respect to our common units while they are aware of material non-public information and 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."

Independence Determinations and 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, Corbin J. Robertson III and Kenneth M. Jastrow II serve as the members of the audit committee. Ms. Gasaway is the chairperson. Our board of directors believes that Ms. Gasaway qualifies as an audit committee financial expert 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.

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.

The following individuals constitute the G&C Committee:

Kenneth M. Jastrow II, Chairman
James E. Davison
James E. Davison, Jr.
Sharilyn S. Gasaway
Donald L. Evans
Corbin J. Robertson III

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 our general partner or any of its affiliates and us. If a specific review is requested by our board of directors, our conflicts committee would be formed by our Board and would be comprised solely of independent directors. See Item 13. “Certain Relationships and Related Transactions, and Director Independence—Review or Special Approval of

Material Transactions with Related Persons."

Executive Sessions of Non-Management Directors

Our board of directors holds executive sessions in which non-management directors meet without any members of management present in connection with regular board meetings. The purpose of these executive sessions is to promote open

Table of Contents

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 26, 2013. All executive officers serve at the discretion of our general partner.

Name	Age	Position
Grant E. Sims	57	Director, Chairman of the Board, and Chief Executive Officer
James E. Davison	75	Director
James E. Davison, Jr.	46	Director
Donald L. Evans	66	Director
Sharilyn S. Gasaway	44	Director
Kenneth M. Jastrow II	65	Director
Corbin J. Robertson III	42	Director
Steven R. Nathanson	57	President and Chief Operating Officer
Robert V. Deere	58	Chief Financial Officer
Paul A. Davis	49	Senior Vice President
Stephen M. Smith	36	Vice President
Karen N. Pape	54	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 is also a director of Texas Capital Bancshares, Inc. 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.

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 Storage, Inc. Mr. Davison has over forty years 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.

Donald L. Evans has served as a director of our general partner since February 5, 2010. Mr. Evans has served as President of The Don Evans Group, Ltd. since 2005 and served as the 34th Secretary of the U.S. Department of Commerce from 2001 to 2005. Since 2007, Mr. Evans has also served as the Non-Executive Chairman of Energy Future Holdings Corp., a provider of electricity and related services. We believe that Mr. Evans' background and knowledge coupled with the leadership qualities demonstrated by his executive background bring important experience and skill to our board of directors.

Sharilyn S. Gasaway has served as a director of our general partner since March 1, 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

Table of Contents

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 both companies. 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 1, 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 of KB Home and MGIC Investment Corporation, where he also serves on the compensation committee. 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 5, 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.

Steven R. Nathanson became President and Chief Operating Officer in December 2010 and an executive officer of our general partner in February 2010. He had served as President of our refinery services subsidiary, TDC, LLC since 2002.

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 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.

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.”

Code of Ethics

We have adopted a code of ethics that is applicable to, among others, the principal financial officer and the principal accounting officer. The Genesis Energy Financial Employee Code of Professional Conduct is posted at our website (www.genesisenergy.com), where we intend to report any changes or waivers.

Section 16(a) Beneficial Ownership Reporting Compliance

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

Item 11. Executive Compensation

The Compensation Discussion and Analysis below discusses our compensation process, objectives and philosophy with respect to our Named Executive Officers ("NEOs"), for the fiscal year ended December 31, 2012.

Compensation Discussion and Analysis

Named Executive Officers

Our NEOs for 2012 were:

- Grant E. Sims, Chief Executive Officer;
- Steven R. Nathanson, President and Chief Operating Officer;
- Robert V. Deere, Chief Financial Officer;
- Paul A. Davis, Senior Vice President; and
- Stephen M. Smith, Vice President

Board and Governance, Compensation and Business Development Committee

Our board of directors is responsible for, and effectively determines, compensation matters. Our board of directors has delegated to the G&C Committee, a majority of the members of which are "independent," the authority and responsibility to regularly analyze and reconsider our compensation policies, to determine the annual compensation of our employees, 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 the compensation of the other NEOs, which proposal is based on (among other things) our financial results for the prior year, the individual executive's areas of responsibility, 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.

Committee/Board Approval

The G&C Committee determines compensation and long-term awards for executive officers, taking into consideration the CEO's recommendation regarding the NEOs. Following approval of the entire annual compensation program in the first quarter of each year, any applicable salary increases and long-term incentive awards are made or granted. Bonuses are paid in March.

Role of Compensation Consultant

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 2012, 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 listings 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 prepared for and circulated to the G&C Committee and management's proposed executive compensation

Table of Contents

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 does not determine or recommend the amount of compensation.

The peer group used for this analysis consisted of the following 18 companies in the energy industry: Blueknight Energy Partners, Buckeye Partners, Copano Energy, LLC, Crosstex Energy Partners, DCP Midstream Partners, Eagle Rock Energy Partners, Holly Energy Partners, Magellan Midstream Partners, NuStar Energy, LP, Penn Virginia Resource Partners, Regency Energy Partners, Sunoco Logistics, LP, Targa Resource Partners, Amerigas Partners, Calumet Specialty Products Partners, HollyFrontier Corporation, Natural Resource Partners and Western Refining.

These companies were selected as the compensation peer group because: they

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

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 maximizing cash distributions and growth in 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 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 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. Compensation that is earned over the long-term through service and performance-based opportunities aims to assure an alignment between executives and investors in the organization. The amount of compensation contingent on performance is weighted with a significant emphasis of performance as a 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 the appreciation in our common unit price and increases in the distribution rate on our common units, which we believe links pay with performance and creates an alignment of interest between our NEOs and our unitholders.

Table of Contents

Elements of Our Compensation Program and Compensation Decisions for 2012
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, 2012, 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 based on recommendations from our CEO. 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 analyses of peer group practices as described above.
In April 2012, 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. Sims’ salary was increased 5% to $500,000, Mr. Nathanson's salary was increased 14% to $375,000, Mr. Deere's salary was increased 5% to $440,000, Mr. Smith’s salary was increased 14% to $250,000. Mr. Davis' salary was not adjusted as he was hired in March 2012 at a salary that we felt was appropriate based on the scope of his responsibilities, future potential and market levels. 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.
Bonuses
Our NEOs participate in a bonus program, or the Bonus Plan, in which 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 2012, the G&C Committee set each NEO’s bonus target as a percentage of salary as follows:

Name	2012 Bonus Target (% of base salary)
Grant E. Sims	100%
Steven R. Nathanson	100%
Robert V. Deere	50%
Paul A. Davis	100%
Stephen M. Smith	100%

The Bonus Plan is designed to reward employees on a basis that is aligned with the interests of our unitholders. 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. Safety objectives encourage our employees to focus on the impact their job performance has on

Table of Contents

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. See Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for a description of Available Cash before Reserves.

The 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.

The total 2012 pool approved for such bonuses, inclusive of other discretionary downward adjustments, was approximately $7.8 million. From the general bonus pool amount, the G&C Committee approved 2012 bonuses of $425,000, $375,000, $200,000, $200,000 and $250,000 to Messrs. Sims, Nathanson, Deere, Davis, and Smith, respectively. The bonuses were approved based on the G&C Committee’s review of the operational and financial performance of the company, industry expectations and individual performance. The bonuses will be paid in March 2013.

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. 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 the 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.

Long-term incentive awards are expressed as a percentage of base salary. This percentage reflects the expected fair value of the awards to be granted in aggregate each year. 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 bonus for each NEO. For 2012, the G&C Committee established the following long-term incentive target percentages (expressed as a percent of base salary) for each of our NEOs:

Name	2012 Long-Term Incentive Target

	(% of base salary)
Grant E. Sims	225%
Steven R. Nathanson	200%
Robert V. Deere	100%
Stephen M. Smith	125%

In April 2012, phantom units were granted to certain NEOs (Mr. Davis was not granted a phantom unit award due to his recent hiring in March 2012) and certain non-officer employees under the 2010 LTIP. 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

Table of Contents

date of vesting. The phantom units granted to our NEOs in April 2012 were all performance-based awards while phantom units granted to our non-officer employees, were apportioned 60% to performance-based awards and 40% to service-based awards. The service-based awards vest on the third year anniversary from the date of grant.

Between 50% and 150% of the number of performance-based awards granted to our NEOs and non-officer employees will vest on the third anniversary of issuance if certain quarterly cash distribution targets are achieved in the fourth quarter of 2014. Should the quarterly cash distribution on the common units fall between the range of $0.49 per unit and $0.57 per unit, the phantom units will vest between 50% and 150% of the number granted on a pro rata basis. If the quarterly cash distribution is below $0.49 per unit for the fourth quarter of 2014, all of the performance-based phantom units granted will be forfeited. 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%, these awards will vest as follows:

(i) if the quarterly cash distribution on the common units is $0.49 per unit, 50% of the phantom units granted will vest, and the remainder will be forfeited;

(ii) if the quarterly cash distribution on the common units is $0.53 per unit, 100% of the phantom units granted will vest; or

(iii) if the quarterly cash distribution on the common units is $0.57 per unit or greater, 150% of the phantom units granted will vest.

Should the quarterly cash distribution on the common units fall between the range of $0.49 per unit and $0.57 per unit, the phantom units will vest between 50% and 150% of the number granted on a proportionately adjusted basis (for example, if the quarterly cash distribution on the common units is $0.51 per unit, 75% of the phantom units granted will vest or if the quarterly cash distribution on the common units is $0.55 per unit, 125% of the phantom units granted will vest). If the quarterly cash distribution is below $0.49 per unit for the fourth quarter of 2014, all of the performance-based phantom units granted will be forfeited.

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.

Equity Award Granted to Paul A. Davis

In connection with Mr. Davis' appointment as Senior Vice President of our general partner in March 2012, he received, and fully vested in, a one-time new-hire equity award equivalent to $500,000 of grant date fair market value, which we determined was appropriate based on our assessment of the competitive compensation market and Mr. Davis' experience in the industry and the scope of his responsibilities. Mr. Davis' equity award consisted of 12,206 Class A Units and 2,946 Waiver Units.

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 that this uncertainty may 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. Sims, Nathanson, Deere and Davis provide certain compensation and benefits as an incentive for the executive to remain in our employ and enhance our ability to call on and rely upon the executive in the event of a change of control. None of these NEOs 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 "Employment Agreements" below for further discussion of employment agreements, 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.

For more details on the benefits and payouts under various termination scenarios, including in connection with a change of control, see “Potential Payments upon Termination or Change of Control.”

Table of Contents

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.

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
Donald L. Evans
Corbin J. Robertson III

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;
- 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.

Table of Contents

Summary Compensation Table

The following Summary Compensation Table summarizes the total compensation paid or accrued to our NEOs in 2012, 2011 and 2010.

Name & Principal Position	Year	Salary ($)	Bonus ($) (1)	Stock Awards ($) (2)	All Other Compensation ($) (4)	Total ($)
Grant E. Sims	2012	$492,308	$425,000	$1,198,716	$147,882	$2,263,906
Chief Executive Officer	2011	460,962	450,000	839,346	74,978	1,825,286
(Principal Executive Officer)	2010	440,000	446,200	4,186,488	72,262	5,144,950
Steven R. Nathanson	2012	361,154	375,000	556,336	94,671	1,387,161
President and	2011	323,654	420,000	499,807	58,087	1,301,548
Chief Operating Officer	2010	320,067	320,100	2,259,069	66,187	2,965,423
Robert V. Deere	2012	433,846	200,000	468,817	77,737	1,180,400
Chief Financial Officer	2011	411,923	130,000	424,085	37,285	1,003,293
(Principal Financial Officer)	2010	413,167	101,850	805,066	61,696	1,381,779
Paul A. Davis [3]	2012	215,385	200,000	500,000	10,581	925,966
Senior Vice President						
Stephen M. Smith	2012	240,769	250,000	332,973	56,343	880,085
Vice President	2011	209,231	220,000	222,149	23,091	674,471
	2010	226,247	194,000	1,097,914	38,766	1,556,927

(1) Bonuses are paid in March of the following year (e.g., the bonuses with respect to 2012 will be paid in March 2013).

(2) The amounts shown in this column represent the aggregate grant date fair value for each NEO's phantom units granted in 2011 and 2012 under our 2010 Long-Term Incentive Plan, excluding the amount shown for Mr. Davis. The 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. Amounts in 2010 also include the aggregate grant date fair value for each NEO's Series B Award. The Series B Awards provided for the conversion into Series A units in our general partner under certain conditions. These awards were ultimately exchanged for our Class A Units and Waiver Units in connection with our IDR Restructuring. For additional information on these awards and our IDR Restructuring see Note 15 to our Consolidated Financial Statements in Item 8. 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) The following table presents the components of "All Other Compensation" for each NEO for the year ended December 31, 2012.

Name	401(k) Matching and Profit Sharing Contributions (a)	Insurance Premiums (b)	Other Compensation (c)	Totals
Grant E. Sims	$7,500	$2,700	$137,682	$147,882
Steven R. Nathanson	$20,515	$2,700	$71,456	$94,671
Robert V. Deere	$17,654	$2,700	$57,383	$77,737
Paul A. Davis	$9,046	$1,535	$—	$10,581
Stephen M. Smith	$20,700	$2,183	$33,460	$56,343

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.

Table of Contents

Grants of Plan-Based Awards in Fiscal Year 2012

The following table shows equity incentive plan awards granted to our NEOs in 2012.

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	4/10/2012	19,100	38,200	57,300	$29.45	$1,198,716
Steven R. Nathanson	4/10/2012	8,865	17,729	26,594	$29.45	$556,336
Robert V. Deere	4/10/2012	7,470	14,940	22,410	$29.45	$468,817
Stephen M. Smith	4/10/2012	5,306	10,611	15,917	$29.45	$332,973

(1) Represents the number of phantom units that each NEO can earn of grant awarded on April 10, 2012, if the company meets certain performance conditions (threshold, target and maximum) during the fourth quarter of 2014. Upon achieving either the threshold, target or maximum levels during the fourth quarter of 2014 the NEO earns either 50% of the initial grant, 100% of the initial grant or 150% of the initial grant, respectively. The target level represents the number of phantom units initially issued on the grant date. The performance targets are as follows: (i) at threshold, if the quarterly cash distribution on the common units is $0.49 per unit, 50% of the phantom units granted will vest and the remainder will be forfeited; (ii) at target, if the quarterly cash distribution on the common units is $0.53 per unit, 100% of the phantom units granted will vest; or (iii) at maximum, if the quarterly cash distribution on the common units is $0.57 per unit or greater, 150% of the phantom units granted will vest. Should the quarterly cash distribution on the common units fall between the range of $0.49 per unit and $0.57 per unit, the phantom units will vest between 50% and 150% of the number granted on a proportionately adjusted basis (for example, if the quarterly cash distribution on the common units is $0.51 per unit, 75% of the phantom units granted will vest or if the quarterly cash distribution on the common units is $0.55 per unit, 125% of the phantom units granted will vest). If the quarterly cash distribution is below $0.49 per unit for the fourth quarter of 2014, all of the phantom units granted will be forfeited.

(2) Represents the closing market price of our common units on the date of the phantom unit award on April 10, 2012.

(3) The amounts in this column for each NEO represent the fair value of the award on the date of the grant, based on a target performance payout (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 ($31.38).

Employment Agreements

Grant E. Sims and Robert V. Deere

In December 2008, each of Messrs. Sims and Deere entered into four-year employment agreements, which were amended in February 2010 and automatically terminated by their terms on December 31, 2012. As of December 31, 2012, the annual base salaries of Messrs. Sims and Deere were $500,000 and $440,000, respectively.

Each 2008 employment agreement contained customary non-solicitation and non-competition provisions that prohibits the executive from competing with us for a period of one year after termination of the employment agreement. Under those employment agreements, Messrs. Sims and Deere were entitled to specified severance benefits under certain circumstances described below.

Each of Messrs. Sims and Deere (or his respective family) would have been entitled to continued health benefits for 18 months after his termination and to the payment of his base salary through December 31, 2012 if he had died or had been terminated due to a disability or if he had terminated his employment for good reason. If our general partner had terminated Mr. Sims or Mr. Deere (other than for cause) within two years after a change of control, he would have been entitled to continued health benefits for 18 months after his termination to the extent that such benefits were subsidized by the Partnership for its active employees and to the payment of his base salary up through the third year from his date of termination. As of January 1, 2013, neither of Messrs. Sims nor Deere are entitled to the benefits under his terminated employment agreement. As used in the employment agreements of Messrs. Sims and Deere, the terms “cause,” “good reason” and “disability” were generally described below:

- “Cause” means, in general, if an executive commits willful fraud or theft of our assets, is convicted of a felony or crime of moral turpitude, materially violates certain provisions of his employment agreement, substantially fails to perform, is grossly negligent, acts with willful misconduct, acts in a way materially injurious to us, willfully

Table of Contents

violates material written rules, regulations or policies, or fails to follow reasonable instructions from the audit committee, and such failure to follow instructions could reasonably be expected to be materially injurious to us.

- “Good reason” means, in general, an executive's duties, responsibilities, base salary, or benefits are materially diminished, if either our principal executive office or that executive is based anywhere outside of metropolitan Houston without his consent, if our general partner fails to make a material payment under, or perform a material provision of, his employment agreement, or our general partner amends or changes certain equity interests in a manner that materially and adversely affects the executive's right to distributions or redemptions payable because of such amendment or change, subject to certain exceptions.

- “Disability” means, in general, if the executive has been absent from his duties with us on a full-time basis for 180 out of any 220 consecutive calendar days as a result of incapacity due to mental or physical illness or injury that is determined to be total and permanent by a selected physician or if the Social Security Administration has determined that executive is totally disabled.

Steven R. Nathanson

Mr. Nathanson entered into an employment agreement with our general partner in July 2007, at a base salary which is subject to discretionary upward adjustments. Currently, the annual base salary of Mr. Nathanson is $375,000. The agreement also provides that Mr. Nathanson 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. Mr. Nathanson’s employment arrangement includes customary non-competition restrictions following his termination and severance benefits in the event of termination by the company for reasons other than cause or a termination of Mr. Nathanson for cause. See additional discussion in "Potential Payments upon Termination or Change in Control" below.

Paul A. Davis

Mr. Davis entered into a letter agreement in March 2012, at a base salary which is subject to discretionary upward adjustments. Currently, the annual base salary of Mr. Davis is $280,000. The agreement also 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 in Control" below.

Stephen M. Smith

Mr. Smith does not have an employment agreement with us.

Table of Contents

Outstanding Equity Awards at December 31, 2012

The following table presents the information regarding the outstanding equity awards to our NEOs at December 31, 2012.

		Stock Appreciation Rights			Stock Awards			
Name	Grant Date	Number of Securities Underlying Stock Appreciation Rights Exercisable (#) (1)	Stock Appreciation Rights Exercise Price ($)	Stock Appreciation Rights Expiration Date	Number of Phantom Units That Have Not Vested (#) (2)	Market Value of Phantom Units That Have Not Vested ($) (3)	Equity Incentive Plan Awards: Number of Unearned Phantom Units That Have Not Vested (#) (4)	Equity Incentive Plan Awards: Market Value of Unearned Phantom Units That Have Not Vested ($) (3)
Grant E. Sims	4/10/2012						19,100	$667,020
	4/29/2011						14,887	$519,891
	4/20/2010				16,795	$586,523		
Steven R. Nathanson	4/10/2012						8,865	$309,588
	4/29/2011						8,865	$309,588
	4/20/2010				8,030	$280,428		
	2/14/2008	16,465	$ 20.92	2/14/2018				
Robert V. Deere	4/10/2012						7,470	$260,871
	4/29/2011						7,522	$262,687
	4/20/2010				5,110	$178,454		
Stephen M. Smith	4/10/2012						5,306	$185,299
	4/29/2011						3,940	$137,595
	4/20/2010				2,430	$84,862		

(1) All rights in this column were vested at December 31, 2012.
(2) The phantom unit awards granted in 2010 vest on April 20, 2013.
(3) 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.
(4) The number of performance units reflected in the table assumes a threshold performance payout during the fourth quarter of 2013 for units granted on April 29, 2011 and the fourth quarter of 2014 for units granted on April 10, 2012 (at which 50% of the initial phantom units awarded will vest on the third year anniversary from the date of grant). The phantom units will vest at the end of three years between 50% and 150% of the number granted, if certain quarterly cash distribution target levels for the fourth quarter of 2013 and fourth quarter of 2014 are achieved.

Potential Payments upon Termination or Change in Control

Each of Messrs. Sims, Nathanson, Deere and Davis is entitled under his employment agreement to specified severance benefits under certain circumstances as discussed above under "Employment Agreements." As further discussed above, Messrs. Sims and Deere's employment agreements terminated by their terms on December 31, 2012. As of January 1, 2013, neither of Messrs. Sims nor Deere are entitled to the benefits under his terminated employment agreement.
Under a change in control and certain termination circumstances, our NEOs also will vest in any outstanding awards under our 2010 LTIP. Under the 2010 LTIP, a change in 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.
After his termination other than a voluntary termination or for cause, including in the event of a change of control, during the initial term of Mr. Nathanson's employment agreement, Mr. Nathanson would be entitled to (i) continued health benefits for the remainder of the term of his employment agreement for up to 18 months and (ii) the greater of (x) payment of

Table of Contents

his base salary for one year and (y) payment of his base salary for the remainder of the term of his employment agreement, but in no event for more than 18 months.

As used in the employment agreement of Mr. Nathanson, the terms "cause" and "change of control" 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.
- "Change of control" means, in general, any sale of equity of us or our general partner or substantially all of the assets of us or our general partner, merger, conversion or consolidation of us or our general partner, or other event that, in each case, results in any person or entity (or other persons or entities acting in concert) having the ability to elect a majority of the members of our board of directors.

After his termination other than a voluntary termination or for cause, including in the event of a change of control, Mr. Davis would be entitled to (i) continued health benefits for the remainder of the term of his employment agreement for up to 18 months, (ii) the greater of (x) payment of his base salary for one year and (y) payment of his base salary for the remainder of the term of his employment agreement, but in no event for more than 24 months; and (iii) to the greater of (x) a bonus payment of 100% of his base salary for one year and (y) a bonus payment of 100% of his base salary for the remainder of the term of his employment agreement, but in no event for more than 200% of his base salary for one year.

As used in the employment agreement of Mr. Davis, the terms "cause" and "change of control" 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.
- "Change of control" means, in general, any sale of equity of us or our general partner or substantially all of the assets of us or our general partner, merger, conversion or consolidation of us or our general partner, or other event that, in each case, results in any person or entity (or other persons or entities acting in concert) having the ability to elect a majority of the members of our board of directors.

Based upon a hypothetical termination date of December 31, 2012, the termination benefits for Messrs. Sims, Nathanson, Deere, Davis and Smith for voluntary termination or termination for cause would be zero.

Based upon a hypothetical termination date of December 31, 2012, the termination benefits for Messrs. Sims, Nathanson, Deere and Davis for termination without cause or for good reason, including death or disability would have been:

	Grant E. Sims	Steven R. Nathanson	Robert V. Deere	Paul A. Davis
Severance pursuant to employment agreement	$500,000	$375,000	$440,000	$1,120,000
Healthcare	24,180	20,551	30,826	30,826
Total	$524,180	$395,551	$470,826	$1,150,826

If termination occurs due to death or disability, Messrs. Sims, Nathanson, Deere and Smith 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, 2012 would result in payments under the 2010 LTIP of the following amounts upon death or disability:

Grant E. Sims	$2,960,310

Steven R. Nathanson	$1,518,710
Robert V. Deere	$1,225,535
Stephen A. Smith	$730,614

Table of Contents

Based on a hypothetical simultaneous change of control and termination date of December 31, 2012, the change of control termination benefits for Messrs. Sims, Nathanson, Deere, Davis and Smith would have been as follows:

	Grant E. Sims	Steven R. Nathanson	Robert V. Deere	Paul A. Davis	Stephen M. Smith
Severance pursuant to employment agreement	$1,500,000	$375,000	$1,320,000	$1,026,667	$—
Healthcare	24,180	20,551	30,826	30,826	—
Cash payment for vested phantom units under 2010 LTIP	2,960,310	1,518,710	1,225,535	—	730,614
Total	$4,484,490	$1,914,261	$2,576,361	$1,057,493	$730,614

Director Compensation in Fiscal Year 2012

The table below reflects compensation for the directors.

	Fees Earned or Paid in Cash ($) (1)	Stock Awards ($) (2) (3)	All Other Compensation ($) (4)	Total
Current Directors				
James E. Davison	$ 77,000	$75,000	$ 13,096	$165,096
James E. Davison, Jr.	$ 77,000	$75,000	$ 13,096	$165,096
Donald L. Evans (6)	$ 78,500	$75,000	$ 13,096	$166,596
Sharilyn S. Gasaway	$ 96,000	$85,000	$ 14,836	$195,836
Kenneth M. Jastrow II	$ 85,625	$80,625	$ 13,878	$180,128
Corbin J. Robertson III (6)	$ 77,125	$75,625	$ 13,104	$165,854
Former Directors (5)				
S. James Nelson	$ 69,625	$60,625	$ 9,913	$140,163
William K. Robertson (6)	$ 58,250	$56,250	$ 9,289	$123,789
Robert C. Sturdivant (6)	$ 58,250	$56,250	$ 9,289	$123,789
Carl A. Thomason	$ 64,875	$56,875	$ 9,299	$131,049

(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, 2012 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 8,057 outstanding phantom units and 1,000 stock appreciation rights. Messrs. Evans, Jastrow, C. Robertson and Ms. Gasaway hold 8,057, 8,612, 8,075, and 9,128 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.

(5) In October 2012, certain directors resigned from the board of directors of our general partner. In connection with those directors' resignations, we paid Messrs. Nelson, W. Robertson, Sturdivant and Thomason $268,750, $251,392, $251,392 and $252,129, respectively, related to phantom units granted under our 2010 LTIP that were outstanding as of September 30, 2012. Proceeds from the phantom units held by Messrs. W. Robertson and Sturdivant were paid to an affiliate of Quintana.

(6) Prior to September 30, 2012, all fees paid and amounts paid for DERs related to phantom unit awards for these directors were paid to an affiliate of Quintana. After September 30, 2012, all fees paid and amounts paid for DERs related to phantom unit awards for Messrs. Evans and C. Robertson, were paid directly to the

individuals.

Directors who are not officers of our general partner are entitled to a base compensation of $150,000 per year, with $75,000 paid in cash and $75,000 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 are service-based and vest on the third anniversary from the date of grant. The determination of 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 quarterly amount to be paid in phantom units. So long as he or she is a director on the

Table of Contents

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.

Chairpersons of the audit committee as well as the 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 $20,000 for the chair of the audit committee and $10,000 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 $2,000 per meeting, and participation by a director by means of telecommunication will entitle her/him to additional compensation of $1,500 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.

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, 2012, 2011 or 2010. For additional discussion of our 2007 LTIP, see Note 15 to our Consolidated Financial Statements in Item 8.

Table of Contents

Beneficial Ownership of Partnership Units

The following table sets forth certain information as of February 22, 2013, regarding the beneficial ownership of our Class A Common Units and Class B Common Units by beneficial owners of 5% or more of such units, 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.

	Class A Common Units		Class B Common Units		Class 3 Waiver Units		Class 4 Waiver Units	
Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership (1)	Percent of Class	Amount and Nature of Beneficial Ownership	Percent of Class	Amount and Nature of Beneficial Ownership	Percent of Class	Amount and Nature of Beneficial Ownership	Percent of Class
James E. Davison	3,536,256 (2)	4.4 %	9,453	23.6 %	91,823	5.3 %	91,823	5.3 %
James E. Davison, Jr.	5,140,286 (3)	6.3 %	13,648	34.1 %	91,823 (4)	5.3 %	91,823 (4)	5.3 %
Donald L. Evans (5)	44,451	*	—	—	7,652	*	7,652	*
Sharilyn S. Gasaway	238,839	*	1,081	2.7 %	15,303	*	15,303	*
Kenneth M. Jastrow II	—	—	—	—	—	—	—	—
Corbin J. Robertson III	1,590,765 (6)	2.0 %	—	—	110,401 (7)	6.4 %	110,401 (7)	6.4 %
Grant E. Sims	2,591,029 (8)	3.2 %	7,087	17.7 %	198,459	11.4 %	198,459	11.4 %
Steven R. Nathanson	854,307 (9)	1.1 %	—	—	53,944	3.1 %	53,944	3.1 %
Robert V. Deere	653,637	*	1,052	2.6 %	48,675	2.8 %	48,675	2.8 %
Paul A. Davis	13,188	*	—	—	982	*	982	*
Stephen M. Smith	362,200 (10)	*	—	—	26,972	1.6 %	26,972	1.6 %
Karen N. Pape	134,323	*	—	—	8,904	*	8,904	*
All directors and executive officers as a group (12 in total)	15,159,281	18.7 %	32,321	80.8 %	654,938	37.7 %	654,938	37.7 %
Steven K. Davison	2,785,195 (11)	3.4 %	7,676	19.2 %	91,822 (12)	5.3 %	91,822 (12)	5.3 %

*Less than 1%

(1) The Class B Common Units, which are included in the Class A Common Unit total, are identical to the Class A Common Units and, accordingly, have voting and distribution rights equivalent to those of the Class A Common Units, and, 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. James E. Davison is the sole stockholder of Davison Terminal Service, Inc., which directly owns 1,010,835 Class A Common Units.

(3) Mr. Davison, Jr. pledged 2,972,711 of these Class A Common Units as collateral for a loan from a bank. 1,155,737 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) 91,823 of each class of our outstanding Waiver Units are held by trusts for Mr. Davison's children.

(5) Mr. Evans is a member of the board of managers of QEP Management Co. GP, LLC, a Delaware limited liability company ("Management Co GP"), a member of the board of directors and senior partner of Quintana Capital Group GP, Ltd., a Cayman Islands company ("QCG GP"), and partner of Quintana Capital Group II, L.P., a Cayman Islands limited partnership ("QCG II"); Each of Quintana Energy Partners II, L.P., a Cayman Islands limited partnership ("QEP II"), and QEP II Genesis TE Holdco, LP, a Delaware limited partnership ("Holdco"), has (i) QCG II as its general partner (with QCG GP as the general partner of QCG II), (ii) management services provided by QEP Management Co., L.P., a Delaware limited partnership ("QEP Management") (with Management Co GP as the general partner of QEP Management) and (iii) membership interests in Q GEI. Mr. Robertson, III is the chief executive officer, president and a member of the board of managers of Q GEI, a manager of Management Co GP, a member of the board of directors and managing director of QCP GP, a member of Q GEI and a partner in QCG II; The Corbin J. Robertson III 2009 Family Trust is a member of Q GEI. Each such person disclaims beneficial ownership of all the units reported by such entities.

(6) Mr. C. Robertson pledged 1,300,000 of these Class A Common Units as collateral for a loan from a bank. Includes 172,951 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 Robertson 2006 Family Trust.

Table of Contents

(7) The Corbin J. Robertson III 2009 Family Trust holds 12,917 of each class of our outstanding Waiver Units and Mr. C. Robertson III holds 97,484 of each class of our outstanding Waiver Units.
(8) Mr. Sims pledged 866,334 of these Class A Common Units as collateral for a loan from a bank. Includes 1,000 Class A Common Units held by Mr. Sims' father, of which Mr. Sims disclaims beneficial ownership.
(9) Includes 291,208 Class A Common Units held in trusts in the names of Mr. Nathanson's children, of which Mr. Nathanson disclaims beneficial ownership.
(10) Includes 100,000 Class A Common Units that are held in a margin brokerage account.
(11) Includes 132,245 Class A Common units held by the Steven Davison Family Trust.
(12) The Steven Davison Family Trust holds 22,848 of each class of our outstanding Waiver Units and Mr. S. Davison holds 68,974 of each class of our outstanding Waiver Units. The mailing address for Mr. S. Davison is 2000 Farmerville Highway, Ruston, Louisiana, 71270.

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

The Quintana Group monetized all of its remaining investment in us on October 5, 2012, with members of the Davison family, our CEO, Mr. Sims, and certain members of our board of directors purchasing an aggregate 34,998 (or 87.5%) of our Class B Common Units at a price of $30.00 per unit in a private placement transaction. See Item 10. "Directors, Executive Officers and Corporate Governance" for a discussion of certain arrangements with the members of the Davison family to appoint directors and Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" for a description of such investors' ownership interest in us.
During 2012, we sold $1.3 million of petroleum products to businesses owned and operated by members of the Davison family in the ordinary course of our operations.
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 2012. Based on current market rates for chartering of private aircraft, we believe that the terms of this arrangement are no worse than what we could have obtained in an arms-length transaction.
Family members of certain of our executive officers and directors may work for us from time to time. In 2012, each of Messrs. Sims (our CEO and a director) and James Davison, Sr. (a director) had a son (in the case of James Davison, Sr., who is also a brother of James E. Davison, Jr. a director), that worked as a non-executive employee in our business development and supply and logistics departments, respectively, and received total W-2 compensation of greater than $120,000 but less than $300,000.

Review or Special Approval of Material Transactions with Related Persons

Before we consider entering into a material transaction with our general partner or any of its affiliates, we determine whether the proposed transaction (1) would comply with the requirements under our credit facility, (2) would comply with substantive law, (3) would comply with our partnership agreement, and (4) would be fair to us and our limited partners. For transactions that are not material, we use "review and approval procedures" that we believe are commensurate with the size and nature of the underlying transaction, which could involve obtaining appraisals from third parties, having informal discussions with board members and/or management or other process that we determine suitable. In addition, our board of directors may form a conflicts committee to review specific matters that our board of directors believes may involve conflicts of interest between our general partner or any of its affiliates and us. In which case, the conflicts committee:

- would evaluate and, where appropriate, negotiate certain material terms of the proposed transaction;

Table of Contents

- may engage an independent legal counsel and, if it deems appropriate, an independent financial adviser to assist with its evaluation of the proposed transaction; and
- would determine whether to reject or approve and recommend the proposed transaction.

For example, a conflicts committee was formed and approved our acquisition of the 51% economic interest in DG Marine that we did not own in July 2010. Additionally, a conflicts committee was formed and approved our IDR Restructuring (see Note 11 to our Consolidated Financial Statements in Item 8).

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 under the NYSE rules, or a nominating or 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 and Jastrow, each of whom is a member of the audit committee, is an independent director under the NYSE rules. See Item 10. "Directors, Executive Officers and Corporate Governance" for additional discussion of director independence.

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, 2012 and 2011.

	2012	2011
	(in thousands)	
Audit Fees (1)	$2,524	$2,555
Audit-Related Fees (2)	20	220
Tax Fees (3)	768	938
All Other Fees (4)	4	4
Total	$3,316	$3,717

(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 (i) reviewing our documentation of controls and process for conversion related to our project to upgrade our information technology systems and (ii) review of correspondence with the SEC. 2011 also includes fees for the audit of our employee benefit plan.

(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 2012 and 2011 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 2012 and 2011, the audit committee determined that such services are compatible with the provision of independent audit services. The audit committee discussed

Table of Contents

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.

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 between Valero Energy Corporation, Valero Services, Inc., Valero Unit Investments, LLC, Genesis Energy, LP, Genesis CHOPS I, LLC and Genesis CHOPS II, LLC dated October 22, 2010 (incorporated by reference to Exhibit 2.2 to Form 10-Q for the quarter ended September 30, 2010).
2.2	Agreement and Plan of Merger by and among Genesis Energy, L.P., Genesis Acquisition, LLC and Genesis Energy, LLC dated as of December 28, 2010 (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K dated January 3, 2011, File No. 001-12295).
2.3	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).
2.4	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).
2.5	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).
2.6	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).
2.7	Purchase and Sale Agreement between Denbury Onshore, LLC and Genesis Free State Pipeline, LLC dated May 30, 2008 (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K dated June 5, 2008, 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 3, 2011, 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).
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	Indenture 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).

Table of Contents

	4.3	Supplemental Indenture, 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).
	4.4	Second Supplemental Indenture, 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).
	4.5	Third Supplemental Indenture, 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).
	4.6	Fourth Supplemental Indenture, 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).
	4.7	Fifth Supplemental Indenture, 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).
	4.8	Sixth Supplemental Indenture, 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).
	4.9	Seventh Supplemental Indenture, 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)
	4.10	Eighth Supplemental Indenture, 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)
	4.11	Ninth Supplemental Indenture, 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)
*	4.12	Tenth Supplemental Indenture, 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.
*	4.13	Eleventh Supplemental Indenture, 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.
	4.14	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).
4.15	Registration Rights Agreement dated February 1, 2012 among Genesis Energy L.P., Genesis Energy Finance Corporation, certain subsidiary guarantors named therein and Deutsche Bank Securities Inc., BMO Capital Markets Corp., Citigroup Global Markets Inc., RBC Capital Markets, LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representatives of the initial purchasers (incorporated by reference to the Company's Current Report in Form 8-K dated February 2, 2012, File No. 001-12295).
4.16	Registration Rights Agreement dated February 8, 2013 among Genesis Energy, L.P., Genesis Energy Finance Corporation, certain subsidiary guarantors named therein and Wells Fargo Securities, LLC, as representative of the initial purchasers (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K dated February 11, 2013, File No. 001-12295).
4.17	Davison Registration Rights Agreement (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).
4.18	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).

Table of Contents

4.19		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).
4.20		Amendment No. 3 to the Davison Registration Rights Agreement, dated as of December 28, 2010 (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K dated January 3, 2011, File No. 001-12295).
4.21		Unitholder Rights Agreement (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K dated July 31, 2007, File No. 001-12295).
4.22		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).
4.23		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).
10.1		Third Amended and Restated Credit Agreement, dated as of July 25, 2012, 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 31, 2012, File No. 001-12295).
10.2		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).
10.3		Transportation Services Agreement between Genesis Free State Pipeline, LLC, as Lessor and Denbury Onshore, LLC dated May 30, 2008 (incorporated by reference to Exhibit 10.2 to Form 8-K dated June 5, 2008, File No. 001-12295).
10.4		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).
10.5	+	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).
10.6	+	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).
10.7	+	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).
10.8	+	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).
10.9	+	Genesis Energy, LLC 2010 Long-Term Incentive Plan Form of Directors Phantom Unit with DERs Agreement (incorporated by reference to Exhibit 10.2 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 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).
10.11	+	

		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).
10.12	+	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).
10.13	+	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).
10.14	+	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).
10.15	+	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).

Table of Contents

	10.16	+	Employment Agreement by and between Genesis Energy, Inc. and Steve Nathanson dated July 25, 2007 (incorporated by reference to Exhibit 10.30 to the Company's Current Report on Form 10-K for the year ended December 31, 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	+	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).
	10.19	+	Waiver Agreement (Deere), 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		Purchase Agreement dated November 12, 2010 relating to 7.875% Senior Notes due 2018 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated November 18, 2010, File No. 001-12295).
	10.21		Purchase Agreement dated February 1, 2012 relating to 7.875% Senior Notes due 2018 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated February 2, 2012, File No. 001-12295).
	10.22		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).
	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.
*	23.2		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.

Table of Contents

SIGNATURES

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

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

By: GENESIS ENERGY, LLC,
as General Partner

Date: February 26, 2013

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 26, 2013
/s/ ROBERT V. DEERE Robert V. Deere	Chief Financial Officer, (Principal Financial Officer)	February 26, 2013
/s/ KAREN N. PAPE Karen N. Pape	Senior Vice President and Controller (Principal Accounting Officer)	February 26, 2013
/s/ JAMES E. DAVISON James E. Davison	Director	February 26, 2013
/s/ JAMES E. DAVISON, JR. James E. Davison, Jr.	Director	February 26, 2013
/s/ DONALD L. EVANS Donald L. Evans	Director	February 26, 2013
/s/ SHARILYN S. GASAWAY Sharilyn S. Gasaway	Director	February 26, 2013
/s/ KENNETH M. JASTROW, II Kenneth M. Jastrow, II	Director	February 26, 2013
/s/ CORBIN J. ROBERTSON, III Corbin J. Robertson, III	Director	February 26, 2013

* Genesis Energy, LLC is our general partner.

Table of Contents

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

Table of Contents

All financial statement schedules have been omitted because they are not applicable or the required information is presented in the Consolidated Financial Statements or the Notes to the Consolidated Financial Statements.

(1) The financial statements as of and for the years ended December 31, 2012 and 2011 were included for informational purposes but did not meet the significance test under Regulation S-X Rule 3-09.

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, 2012 and 2011, and the related consolidated statements of operations, comprehensive income (loss), partners' capital, and cash flows for each of the three years in the period ended December 31, 2012. We also have audited the Partnership's internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control - Integrated Framework 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 Partnership's principal executive and principal financial officers, or persons performing similar functions, and effected by the Partnership'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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, 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, 2012, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
February 26, 2013

Table of Contents

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

	December 31, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$11,282	$10,817
Accounts receivable—trade, net	270,925	237,989
Inventories	87,050	101,124
Other	34,777	26,174
Total current assets	404,034	376,104
FIXED ASSETS, at cost	723,225	541,138
Less: Accumulated depreciation	(157,944)	(124,213)
Net fixed assets	565,281	416,925
NET INVESTMENT IN DIRECT FINANCING LEASES, net of unearned income	157,385	162,460
EQUITY INVESTEES	549,235	326,947
INTANGIBLE ASSETS, net of amortization	75,065	93,356
GOODWILL	325,046	325,046
OTHER ASSETS, net of amortization	33,618	30,006
TOTAL ASSETS	$2,109,664	$1,730,844
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable—trade	$258,053	$199,357
Accrued liabilities	54,598	50,071
Total current liabilities	312,651	249,428
SENIOR SECURED CREDIT FACILITY	500,000	409,300
SENIOR UNSECURED NOTES	350,895	250,000
DEFERRED TAX LIABILITIES	13,810	12,549
OTHER LONG-TERM LIABILITIES	15,813	16,929
COMMITMENTS AND CONTINGENCIES (Note 19)		
PARTNERS' CAPITAL:		
Common unitholders, 81,202,752 and 71,965,062 units issued and outstanding at December 31, 2012 and 2011, respectively	916,495	792,638
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$2,109,664	$1,730,844

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

Table of Contents

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

	Year Ended December 31,		
	2012	2011	2010
REVENUES:			
Supply and logistics	$3,797,750	$2,825,768	$1,894,612
Refinery services	196,017	201,711	151,060
Pipeline transportation services	76,290	62,190	55,652
Total revenues	4,070,057	3,089,669	2,101,324
COSTS AND EXPENSES:			
Supply and logistics product costs	3,541,647	2,643,687	1,761,161
Supply and logistics operating costs	165,764	123,121	97,701
Refinery services operating costs	123,477	126,782	88,094
Pipeline transportation operating costs	21,894	16,964	14,777
General and administrative	42,419	34,473	113,406
Depreciation and amortization	61,166	62,190	53,569
Total costs and expenses	3,956,367	3,007,217	2,128,708
OPERATING INCOME (LOSS)	113,690	82,452	(27,384)
Equity in earnings of equity investees	14,345	3,347	2,355
Interest expense	(40,921)	(35,767)	(22,924)
Income (loss) before income taxes	87,114	50,032	(47,953)
Income tax benefit (expense)	9,205	1,217	(2,588)
NET INCOME (LOSS)	96,319	51,249	(50,541)
Net loss attributable to noncontrolling interests	—	—	2,082
NET INCOME (LOSS) ATTRIBUTABLE TO GENESIS ENERGY, L.P.	$96,319	$51,249	$(48,459)
NET INCOME ATTRIBUTABLE TO GENESIS ENERGY, L.P. PER COMMON UNIT:			
Basic and Diluted	$1.23	$0.75	$0.49
WEIGHTED AVERAGE OUTSTANDING COMMON UNITS:			
Basic and Diluted	78,363	67,938	40,560

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

Table of Contents

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

	Year Ended December 31,		
	2012	2011	2010
Net income (loss)	$96,319	$51,249	$(50,541)
Change in fair value of derivatives:			
Current period reclassification to earnings—interest rate swaps	—	—	2,112
Changes in derivative financial instruments—interest rate swaps	—	—	(424)
Comprehensive income (loss)	96,319	51,249	(48,853)
Comprehensive loss attributable to noncontrolling interests	—	—	1,223
Comprehensive income (loss) attributable to Genesis Energy, L.P.	$96,319	$51,249	$(47,630)

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

Table of Contents

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

	Partners' Capital					
	Number of Common Units	Common Unitholders	General Partner	Accumulated Other Comprehensive Loss	Non-controlling Interests	Total Capital
December 31, 2009	39,488	$585,554	$11,152	$ (829)	$23,056	$618,933
Comprehensive income:						
Net income (loss)	—	17,933	(66,392)	—	(2,082)	(50,541)
Interest rate swap losses reclassified to interest expense	—	—	—	1,035	1,077	2,112
Interest rate swap loss	—	—	—	(206)	(218)	(424)
Cash contributions	—	—	2,528	—	13	2,541
Contribution for management compensation (Note 11)	—	—	76,923	—	—	76,923
Cash distributions	—	(58,983)	(11,369)	—	(7)	(70,359)
Acquisition of noncontrolling interest in DG Marine (Note 3)	—	(4,920)	(100)	—	(21,268)	(26,288)
Issuance of units for cash	5,175	116,347	—	—	—	116,347
Issuance of units in exchange for general partner interest (Note 11)	19,854	13,313	(12,742)	—	(571)	—
Issuance of units under LTIP	98	20	—	—	—	20
December 31, 2010	64,615	669,264	—	—	—	669,264
Comprehensive income:						
Net income	—	51,249	—	—	—	51,249
Cash distributions	—	(112,844)	—	—	—	(112,844)
Issuance of units for cash, net (Note 11)	7,350	184,969	—	—	—	184,969
December 31, 2011	71,965	792,638	—	—	—	792,638
Net income	—	96,319	—	—	—	96,319
Cash distributions	—	(142,383)	—	—	—	(142,383)
Issuance of common units for cash, net (Note 11)	5,750	169,421	—	—	—	169,421
Conversion of waiver units (Note 11)	3,476	—	—	—	—	—
Other	12	500	—	—	—	500
December 31, 2012	81,203	$916,495	$—	$ —	$—	$916,495

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

Table of Contents

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

	Year Ended December 31,		
	2012	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$96,319	$51,249	$(50,541)
Adjustments to reconcile net income to net cash provided by operating activities -			
Depreciation and amortization	61,166	62,190	53,569
Amortization and write-off of debt issuance costs and premium	4,037	2,940	3,082
Amortization of unearned income and initial direct costs on direct financing leases	(16,788)	(17,237)	(17,651)
Payments received under direct financing leases	21,804	21,852	21,854
Equity in earnings of investments in equity investees	(14,345)	(3,347)	(2,355)
Cash distributions of earnings of equity investees	23,900	8,592	3,623
Non-cash effect of equity-based compensation plans	7,197	(15)	4,706
Non-cash compensation charge	—	—	76,923
Deferred and other tax (benefits) liabilities	(9,222)	(2,075)	1,337
Unrealized losses on derivative transactions	86	1,002	1,562
Other, net	2,085	87	(159)
Net changes in components of operating assets and liabilities, net of acquisitions (See Note 14)	13,065	(66,931)	(5,487)
Net cash provided by operating activities	189,304	58,307	90,463
CASH FLOWS FROM INVESTING ACTIVITIES:			
Payments to acquire fixed and intangible assets	(146,456)	(27,992)	(12,400)
Cash distributions received from equity investees—return of investment	14,909	11,436	2,859
Investments in equity investees	(63,749)	—	—
Acquisitions	(205,576)	(163,673)	(332,462)
Proceeds from asset sales	773	6,424	1,146
Other, net	(1,508)	1,508	119
Net cash used in investing activities	(401,607)	(172,297)	(340,738)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings on senior secured credit facility	1,674,400	777,600	691,829
Repayments on senior secured credit facility	(1,583,700)	(728,300)	(698,729)
Proceeds from issuance of senior unsecured notes, including premium	101,000	—	250,000
Debt issuance costs	(7,105)	(3,018)	(14,586)
Issuance of common units for cash, net	169,421	184,969	116,347
General partner contributions	—	—	2,528
Distributions to common unitholders	(142,383)	(112,844)	(58,983)
Distributions to general partner interest	—	—	(11,369)
Acquisition of noncontrolling interest in DG Marine	—	—	(26,288)
Other, net	1,135	638	1,140
Net cash provided by financing activities	212,768	119,045	251,889
Net increase in cash and cash equivalents	465	5,055	1,614

Cash and cash equivalents at beginning of period	10,817	5,762	4,148
Cash and cash equivalents at end of period	$11,282	$10,817	$5,762

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

Table of Contents

GENESIS ENERGY, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
1. Organization

We are a 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 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. We manage our businesses through the following three divisions that constitute our reportable segments:

- Pipeline transportation of interstate, intrastate and offshore crude oil, and, to a lesser extent, carbon dioxide (or “CO_2”);
- 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"); 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.

On December 28, 2010, we permanently eliminated our incentive distribution rights (“IDRs”) and converted our 2% general partner interest into a non-economic interest, which we refer to as our IDR Restructuring. We issued Class A Units, Class B Units and Waiver Units to the former stakeholders of our general partner in exchange for the elimination of our IDRs. See Note 11 for additional discussion of our capital structure.

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, 2012 and 2011 and our results of operations, comprehensive income (loss), changes in partners’ capital and cash flows for the years ended December 31, 2012, 2011 and 2010. All intercompany balances and transactions have been eliminated. The accompanying Consolidated Financial Statements include Genesis Energy, L.P. and its operating subsidiaries, Genesis Crude Oil, L.P. and Genesis NEJD Holdings, LLC, and their subsidiaries, and Genesis Energy, LLC. The inclusion of Genesis Energy, LLC in our Consolidated Financial Statements was effective December 28, 2010 due to our IDR Restructuring (see Notes 1 and 11).

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 Cameron Highway Oil Pipeline Company (or “CHOPS”), Southeast Keathley Canyon Pipeline Company, LLC (or “SEKCO”), Poseidon Oil Pipeline Company, L.L.C. (or "Poseidon") and 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.

CHOPS

In November 2010, we acquired a 50% equity interest in CHOPS, a joint venture that owns and operates a crude oil pipeline system in the Gulf of Mexico. Enterprise Products Partners, L.P. indirectly owns the remaining 50% interest in, and operates, the joint venture.

SEKCO

In December 2011, we entered into a joint venture forming SEKCO with Enterprise Products Partners, L.P. to construct a deepwater pipeline serving the Lucius development area in southern Keathley Canyon of the Gulf of Mexico. We own 50% of SEKCO, and Enterprise Products owns the remaining 50% interest. Enterprise Products serves as construction manager and will be the operator of the new pipeline. The 149-mile, 18-inch diameter pipeline, will connect the Lucius-truss spar floating production platform to an existing junction platform at South Marsh Island that is part of the Poseidon pipeline system. The new pipeline is expected to begin service by mid-2014.

Poseidon

In January 2012, we acquired a 28% equity interest in Poseidon, a joint venture that owns and operates a crude oil pipeline system in the Gulf of Mexico. Affiliates of Enterprise Products and Shell each own a 36% interest in Poseidon. An affiliate of Enterprise Products serves as the operator.

Table of Contents

Odyssey

In January 2012, we acquired a 29% equity interest in Odyssey, a joint venture that owns and operates a crude oil pipeline system in the Gulf of Mexico. An affiliate of Shell owns the remaining 71% interest in Odyssey, and an affiliate of Shell serves as the operator.

Noncontrolling Interests

During the year ended December 31, 2010, we held less than 100% interests in two consolidated subsidiaries, DG Marine and Genesis Crude Oil, L.P. During 2010, we acquired the interests in those subsidiaries that we did not already own. In July 2010, we acquired the 51% interest in DG Marine from TD Marine LLC ("TD Marine"), a related party. In connection with our IDR Restructuring in December 2010, when we acquired our general partner, we also acquired the 0.01% general partner's interest in Genesis Crude Oil, L.P. We reclassified the acquired noncontrolling interests in Genesis Crude Oil, L.P. and DG Marine to Genesis Energy, L.P. partners' capital during 2010.

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, 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 15 years for pipelines and related assets, 20 to 25 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 are classified in fixed assets, as they are necessary to ensure efficient and uninterrupted operations of the gathering businesses. These crude oil 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.

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

Table of Contents

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

When a direct financing lease is consummated, 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.

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, 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. The favorable lease and other intangible assets 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. Fully-amortized debt issuance costs and the related accumulated amortization are written-off in conjunction with the refinancing or termination of the applicable debt arrangement.

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 2011, we adopted new accounting guidance, which provides the option to make a qualitative evaluation about the likelihood of goodwill impairment. After performing a qualitative assessment of relevant events and circumstances, 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

Table of Contents

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, 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.

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 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.

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.

Table of Contents

Derivative Instruments and Hedging Activities

When we hold inventory positions in crude oil and petroleum products, we use derivative instruments to hedge exposure to price risk. Derivative transactions, which can include forward contracts and futures positions on the NYMEX, are recorded in the Consolidated Balance Sheets as assets and liabilities based on the derivative's fair value. Changes in the fair value of derivative contracts are recognized currently in earnings unless specific hedge accounting criteria are met. We must formally designate the derivative as a hedge and document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting. Accordingly, changes in the fair value of derivatives are included in earnings in the current period for (i) derivatives accounted for as fair value hedges; (ii) derivatives that do not qualify for hedge accounting and (iii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items. Changes in the fair value of cash flow hedges are deferred in Accumulated Other Comprehensive Income ("AOCI") and reclassified into earnings when the underlying position affects earnings. 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 to our IDR Restructuring, income available to common unit holders was allocated 98% to our limited partners and 2% to the general partner, including general partner allocations for incentive distributions and certain equity-based compensation costs, which our general partner agreed to pay.

Recent and Proposed Accounting Pronouncements

Recently Issued

In July 2012, the FASB issued guidance intended to simplify the impairment test for indefinite-lived intangible assets other than goodwill by giving entities the option to first assess qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired. The results of the qualitative assessment would be used as a basis in determining whether it is necessary to perform the two-step quantitative impairment testing. An entity can choose to perform the qualitative assessment on none, some or all of its indefinite-lived intangible assets, or may bypass the qualitative assessment and proceed directly to the quantitative impairment test. This guidance will be effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012, with early adoption permitted in certain circumstances. We will adopt this guidance on January 1, 2013. Our adoption is not expected to have a material impact on our financial position, results of operations or cash flows.

Recently Adopted

In December 2011, the Financial Accounting Standards Board ("FASB") issued guidance requiring new disclosures for financial instruments and derivative instruments that are eligible for offset in the statement of financial position or subject to a master netting arrangement. The new guidance is effective for us beginning January 1, 2013 and is not expected to have a significant impact on our financial position, results of operations or cash flows.

In June 2011, the FASB issued guidance that modified how comprehensive income is presented in an entity's financial statements. The guidance issued requires an entity to present the total comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements and eliminates the option to present the components of other comprehensive income as part of the statement of equity. We adopted the revised financial statement presentation for comprehensive income beginning January 1, 2012 and it did not have a significant impact on our financial position, results of operations or cash flows. The guidance pertaining to reclassifying items out of accumulated other comprehensive income has been deferred and will be effective for us beginning January 1, 2013. The adoption of this guidance is not expected to have a significant impact on our financial position, results of operations or cash flows.

3. Acquisitions

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. (or “Poseidon”), 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. (or “Odyssey”). 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

Table of Contents

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.

The allocation of the purchase price is summarized as follows:

Property and equipment	$28,456
Equity investees	182,993
Asset retirement obligation assumed	(5,873)
Total allocation	$205,576

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

The table below presents selected unaudited pro forma financial information for the year ended December 31, 2011 incorporating the historical results of the acquired pipeline interests. The unaudited pro forma financial information below has been prepared as if the acquisition had been completed at the beginning of the prior year and is based upon assumptions deemed appropriate by us and may not be indicative of actual results.

	Year Ended December 31, 2011
Pro forma earnings data:	
Revenues	$3,096,693
Equity in earnings of equity investees	$14,770
Net income	$58,349
Basic and diluted earnings per unit:	
As reported net income per unit	$0.75
Pro forma net income per unit	$0.86
As reported units outstanding	67,938
Pro forma units outstanding	67,938

FMT Black Oil Barge Transportation Business

In August 2011, we completed the acquisition of the black oil barge transportation business of Florida Marine Transporters, Inc. and its affiliates ("FMT"). The purchase price was $143.5 million (including $2.5 million for fuel inventory and other costs). The acquired business was comprised of 30 barges (seven of which were initially sub-leased under terms similar to those of an existing FMT lease, which we subsequently purchased in February 2012 for $30.9 million) and 14 push/tow boats which transport heavy refined products, primarily serving refineries and storage terminals along the Gulf Coast, Intracoastal Canal and western river systems of the United States, including the Red, Ouachita and Mississippi Rivers. The August 2011 acquisition and related transaction costs were funded with a portion of the net proceeds from the July 2011 public offering of our common units, whereby we raised approximately $185 million in net proceeds of equity capital. The February 2012 vessels purchase was funded with cash available under our credit facility. See Note 11 for additional information regarding the common unit offering.

F-12

Table of Contents

The financial results of the acquired business are included in the supply and logistics segment from the date of acquisition.

Wyoming Refinery and Pipeline Assets

In November 2011, we acquired a 90% interest in a 3,500 barrel per day refinery located in Converse County, Wyoming, including 300 miles of abandoned 3” to 6” pipeline. Those assets are located near the emerging Powder River Basin portion of the Niobrara Shale. The purchase price was $20 million, which included $1.3 million for product inventories. We funded the acquisition with cash available under our credit facility.

The financial results of the refinery assets are included in the supply and logistics segment and the pipeline assets have been included in the pipeline transportation segment from the date of acquisition.

CHOPS Investment

In November 2010, we acquired a 50% equity interest in CHOPS, a joint venture that owns and operates a crude oil pipeline system in the Gulf of Mexico. The purchase price was approximately $330 million plus approximately $2.5 million of purchase price adjustments.

The funding for this acquisition consisted of $330 million in cash from the issuance of 5,175,000 common units at $23.58 per common unit and the issuance of $250 million of senior unsecured notes. Total net proceeds from the common units offering, after deducting underwriting discounts and commissions and estimated offering expenses and including our general partner’s proportionate capital contribution to maintain its 2% general partner interest, were approximately $119 million.

CHOPS is a 380-mile 24- and 30-inch diameter pipeline constructed in 2004, with capacity to deliver up to 500,000 barrels per day of crude oil from developments in the Gulf of Mexico to major refining markets along the Texas Gulf Coast located in Port Arthur and Texas City. Enterprise Products Partners, L.P. indirectly owns the remaining 50% interest in, and operates, the joint venture.

The following table presents selected unaudited pro forma financial information incorporating the historical 50% equity interest in CHOPS. The effective closing date of our purchase of a 50% equity interest in CHOPS was November 23, 2010. As a result, our Consolidated Statements of Operations for the year ended December 31, 2010 includes our 50% equity investment in CHOPS for the last five weeks of 2010. The unaudited pro forma financial information has been prepared as if the acquisition had been completed on the first day of 2010 rather than the actual closing date. The unaudited pro forma financial information has been prepared based upon assumptions deemed appropriate by us and may not be indicative of actual results.

	Year Ended December 31, 2010
Pro forma earnings data:	
Equity in earnings of equity investees	$15,322
Net loss attributable to Genesis Energy, L.P.	$(55,001)
Basic and diluted earnings per unit:	
As reported net income per unit	$0.49
Pro forma net income per unit	$0.30
As reported units outstanding	40,560
Pro forma units outstanding	44,969

Acquisition of Remaining “Noncontrolling” Interest in DG Marine

In July 2010, we acquired from TD Marine, a related party, their 51% interest in DG Marine for $25.5 million in cash, resulting in DG Marine becoming wholly-owned by us. We funded the acquisition with proceeds from our credit agreement, including (i) paying off DG Marine’s stand-alone credit facility, which had an outstanding principal balance of $44.4 million, and (ii) settling DG Marine’s interest rate swaps, which resulted in $1.3 million being reclassified from Accumulated Other Comprehensive Loss (“AOCL”) to interest expense in the third quarter of 2010. Prior to the acquisition, DG Marine was consolidated as a variable interest entity as certain of our voting rights were not proportional to our 49% economic interest. As a result of the acquisition, we reclassified the acquired noncontrolling interest in DG Marine of $21.3 million to Genesis Energy, L.P. partners’ capital. Additionally, we reduced our partners' capital by $26.3 million for the costs related to the transaction ($25.5 million paid to TD Marine and $0.8 million in direct transaction costs associated with the acquisition). The net effect of Genesis Energy, L.P. partners' capital in our Consolidated Balance Sheet for December 31, 2010 was a decrease of $5 million.

Table of Contents

4. Receivables

Accounts receivable – trade, net consisted of the following:

	December 31,	
	2012	2011
Accounts receivable - trade	$273,297	$239,033
Allowance for doubtful accounts	(2,372)	(1,044)
Accounts receivable - trade, net	$270,925	$237,989

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

	December 31,		
	2012	2011	2010
Balance at beginning of period	$1,044	$1,307	$1,372
Charged to costs and expenses	2,096	373	491
Amounts written off	(768)	(636)	(556)
Balance at end of period	$2,372	$1,044	$1,307

5. Inventories

The major components of inventories were as follows:

	December 31,	
	2012	2011
Petroleum products	$58,943	$70,769
Crude oil	15,885	11,701
Caustic soda	5,636	11,312
NaHS	6,573	7,337
Other	13	5
Total inventories	$87,050	$101,124

At December 31, 2012 and 2011, market values of our inventory exceeded recorded costs.

Table of Contents

6. Fixed Assets and Asset Retirement Obligations

Fixed Assets

Fixed assets consisted of the following:

	December 31, 2012	2011
Pipelines and related assets	$226,831	$167,865
Machinery and equipment	87,502	46,233
Transportation equipment	21,170	21,732
Marine vessels	298,054	262,216
Land, buildings and improvements	15,606	13,140
Office equipment, furniture and fixtures	4,964	3,778
Construction in progress	52,541	14,236
Other	16,557	11,938
Fixed assets, at cost	723,225	541,138
Less: Accumulated depreciation	(157,944)	(124,213)
Net fixed assets	$565,281	$416,925

Depreciation expense was $37.4 million, $27.5 million and $22.5 million for the years ended December 31, 2012, 2011, and 2010, respectively.

Asset Retirement Obligations

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

December 31, 2010	$5,179
Liabilities incurred and assumed in the current period	349
Accretion expense	372
December 31, 2011	5,900
Liabilities incurred and assumed in the current period	5,995
Accretion expense	800
December 31, 2012	$12,695

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.

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

	December 31, 2012	2011
Total minimum lease payments to be received	$320,148	$341,917
Estimated residual values of leased property (unguaranteed)	292	1,287
Unamortized initial direct costs	1,804	1,992
Less unearned income	(159,750)	(176,726)
Net investment in direct financing leases	162,494	168,470
Less current portion (included in other current assets)	(5,109)	(6,010)
Long-term portion of net investment in direct financing leases	$157,385	$162,460

Table of Contents

At December 31, 2012, minimum lease payments to be received for each of the five succeeding fiscal years are $21.3 million for 2013, $21.2 million for 2014 and $20.7 million per year for 2015, 2016 and 2017.

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, 2012 and 2011, the unamortized excess cost amounts totaled $234 million and $97.8 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,		
	2012	2011	2010
Genesis' share of operating earnings	$24,532	$7,910	$3,224
Amortization of excess purchase price	(10,187)	(4,563)	(869)
Net equity in earnings	$14,345	$3,347	$2,355
Distributions received	$38,809	$20,028	$6,482

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,	
	2012	2011
BALANCE SHEET DATA:		
Assets		
Current Assets	$74,906	$12,732
Fixed Assets, net	832,525	441,894
Other Assets	10,202	18,000
Total Assets	$917,633	$472,626
Liabilities and equity		
Current Liabilities	$112,321	$5,891
Other Liabilities	134,731	8,536
Equity	670,581	458,199
Total Liabilities and Equity	$917,633	$472,626

	Year Ended December 31,		
	2012	2011	2010
INCOME STATEMENT DATA:			
Revenues	$162,267	$56,353	$20,013
Operating Income	$80,841	$16,363	$5,881
Net Income	$77,975	$16,322	$5,843

The 2010 income statement data above includes CHOPS since the date of acquisition. We have included in this filing on Form 10-K (i) unaudited financial statements for CHOPS as of December 31, 2012 and 2011 and for the years ended December 31, 2012 and 2011 and (ii) audited financial statements as of December 31, 2010 and the period from November 23, 2010 to December 31, 2010.

Table of Contents

9. Intangible Assets, Goodwill and Other Assets
Intangible Assets
The following table reflects the components of intangible assets being amortized at December 31, 2012 and 2011:

		December 31, 2012			December 31, 2011		
	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	$ 69,167	$25,487	$94,654	$ 62,111	$32,543
Licensing agreements	6	38,678	22,892	15,786	38,678	19,476	19,202
Supplier relationships	2	36,469	36,469	—	36,469	34,105	2,364
Segment total		169,801	128,528	41,273	169,801	115,692	54,109
Supply & Logistics:							
Customer relationships	5	35,430	26,403	9,027	35,430	23,584	11,846
Intangibles associated with lease	15	13,260	2,565	10,695	13,260	2,092	11,168
Trade names	4	18,888	18,888	—	18,888	17,048	1,840
Segment total		67,578	47,856	19,722	67,578	42,724	24,854
Other	5	18,932	4,862	14,070	17,292	2,899	14,393
Total		$256,311	$ 181,246	$75,065	$254,671	$ 161,315	$93,356

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.
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 and other intangible assets are being amortized on a straight-line basis. Amortization expense on intangible assets was $19.9 million, $30.9 million and $26.8 million for the years ended December 31, 2012, 2011 and 2010, respectively.
The following table reflects our estimated amortization expense for each of the five subsequent fiscal years:

	2013	2014	2015	2016	2017
Refinery Services:					
Customer relationships	$7,116	$5,597	$4,405	$3,471	$2,737
Licensing agreements	3,163	2,928	2,711	2,510	2,324
Supply and Logistics:					
Customer relationships	2,165	1,660	1,275	981	757
Intangibles associated with lease	474	474	474	474	474
Other	1,704	1,685	1,671	1,638	1,619
Total	$14,622	$12,344	$10,536	$9,074	$7,911

In the first quarter of 2011, we adjusted the useful lives of our supply and logistics trade names. As a result of this change in the amortization period of our assets, operating income and net income attributable to us for 2011 decreased $7.7 million, or $0.11 per common unit. At December 31, 2012, our supply and logistics trade names were fully amortized.

Goodwill

The carrying amount of goodwill by business segment at both December 31, 2012 and 2011 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,	
	2012	2011
CO_2 volumetric production payments, net of amortization	$8,320	$12,158
Other deferred costs and deposits	25,298	17,848
Other assets, net of amortization	$33,618	$30,006

The CO_2 assets are being amortized on a units-of-production method. We recorded amortization of $3.8 million in 2012, $3.7 million in 2011 and $4.3 million in 2010.

10. Debt

At December 31, 2012 and 2011, our obligations under debt arrangements consisted of the following:

	December 31,	
	2012	2011
Senior secured credit facility	$500,000	$409,300
7.875% senior unsecured notes (including unamortized premium of $895 and $0 in 2012 and 2011, respectively)	350,895	250,000
Total long-term debt	$850,895	$659,300

Senior Secured Credit Facility

In July 2012, we amended and restated our senior secured credit facility with a syndicate of banks to, among other things, increase the committed amount from $775 million to $1 billion and the accordion feature from $225 million to $300 million, giving us the ability to expand the size of the facility up to an aggregate $1.3 billion for acquisitions or internal growth projects, subject to lender consent. The inventory financing sublimit tranche was increased from $125 million to $150 million, and the term of our credit facility was extended to July 25, 2017.

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 1.75% to 2.75% on Eurodollar borrowings and from 0.75% to 1.75% 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, 2012, the applicable margins on our borrowings were 1.0% for alternate base rate borrowings and 2.0% for Eurodollar rate borrowings.
- Letter of credit fees range from 1.75% to 2.75% based on our leverage ratio as computed under the credit facility. The rate can fluctuate quarterly. At December 31, 2012, our letter of credit rate was 2.0%.
- 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 0.375% to 0.50% per annum depending on our leverage ratio (0.375% at December 31, 2012).

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 2.75 to 1.00 (3.00 to 1.00 during an acquisition period).

At December 31, 2012, we had $500 million borrowed under our credit facility, with $63.9 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 $16.7 million was outstanding at December 31, 2012. 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, 2017. The total amount available for borrowings under our credit facility at December 31, 2012 was $483.3 million.

7.875% Senior Unsecured Notes Due 2018

In November 2010, we issued $250 million in aggregate principal amount of 7.875% senior unsecured notes due December 15, 2018. The notes were sold at face value. Interest payments are due on June 15 and December 15 of each year, beginning June 15, 2011. We used the net proceeds from this offering to finance in part the purchase price and related transaction costs for the acquisition of a 50% equity interest in CHOPS.

In February 2012, we issued an additional $100 million of aggregate principal amount of senior unsecured notes under our existing 7.875% senior unsecured notes due 2018 indenture. The notes were issued at 101% of face value at an effective interest rate of 7.682%. The notes have the same terms and conditions as the notes previously issued under the indenture. The issuance increased the total aggregate principal amount under the indenture to $350 million. The net proceeds were used to repay borrowings under our credit facility.

The notes were co-issued by Genesis Energy Finance Corporation (which has no independent assets or operations) and are fully and unconditionally guaranteed, jointly and severally, by certain of our wholly-owned subsidiaries. We have the right to redeem the notes at any time after December 15, 2013 at a premium to the face amount of the notes that varies based on the time remaining to maturity of the notes. Prior to December 15, 2013, we may also redeem up to 35% of the principal amount for 107.875% of the face amount with the proceeds from an equity offering of our common units.

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, 2012, we were in compliance with the financial covenants contained in our credit facility and indenture.

11. Partners’ Capital and Distributions

At December 31, 2012, our outstanding equity consisted of 81,162,755 Class A Units, 39,997 Class B Units and 3,476,466 Waiver 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. The Waiver Units are non-voting securities entitled to a minimal preferential quarterly distribution. At issuance our waiver units were comprised of four classes (designated Class 1, Class 2, Class 3 and Class 4) of 1,738,000 units each. The waiver units in each class are convertible into Class

A common units in the calendar quarter at a 1:1 conversion rate during which each of our common units receives a specified minimum quarterly distribution and our distribution coverage ratio (after giving effect to the then convertible waiver units) would be at least 1.1 times. The minimum distribution per common unit required for conversion is $0.43 (Class 1), $0.46 (Class 2), $0.49 (Class 3) and $0.52 (Class 4).

Table of Contents

On February 14, 2012, our Class 1 waiver units became convertible because we paid a distribution of $0.44 per common unit and satisfied the conversion coverage ratio requirement. All Class 1 waiver units were converted into common units by March 31, 2012.
On August 14, 2012, our Class 2 waiver units became convertible because we paid a distribution of $0.46 per common unit and satisfied the conversion coverage ratio requirement. All Class 2 waiver units were converted into common units by September 30, 2012.
At December 31, 2012, our waiver units outstanding were comprised of the Class 3 and Class 4 waiver units.

IDR Restructuring

Prior to our IDR Restructuring our partners' capital consisted of common units (Class A Units), representing a 98% aggregate ownership interest in the Partnership and its subsidiaries (after giving effect to the general partner interest), a 2% general partner interest, and incentive distribution rights (IDRs). Our general partner owned all of our general partner interest, all of our IDRs, and all of the 0.01% general partner interest in Genesis Crude Oil, L.P. (which was reflected as a noncontrolling interest in the Consolidated Statements of Partners' Capital at December 31, 2009.) IDRs provided our general partner incremental incentive cash distributions when the quarterly cash distribution amount per common unit exceeded certain target thresholds.
In December 2010, the IDRs held by our general partner were eliminated and the 2% general partner interest in us that our general partner held was converted into a non-economic general partner interest. In exchange, we issued to the former owners of our general partner approximately 27,000,000 units, consisting of: (i) approximately 19,960,000 Class A Units, (ii) approximately 40,000 Class B Units and (iii) approximately 7,000,000 Waiver Units.

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 2013, 2012 and 2011 as follows:

Distribution For	Date Paid	Per Unit Amount	Total Amount
2010			
4th Quarter	February 14, 2011	$0.4000	$25,846
2011			
1st Quarter	May 13, 2011	$0.4075	$26,343
2nd Quarter	August 12, 2011	$0.4150	$29,878
3rd Quarter	November 14, 2011	$0.4275	$30,777
4th Quarter	February 14, 2012	$0.4400	$31,677
2012			
1st Quarter	May 15, 2012	$0.4500	$35,768
2nd Quarter	August 14, 2012	$0.4600	$36,563
3rd Quarter	November 14, 2012	$0.4725	$38,375
4th Quarter	February 14, 2013	$0.4850	$39,390

Table of Contents

Net Income per Common Unit
The following table sets forth the computation of basic and diluted net income per common unit.

	Year Ended December 31, 2012	2011	2010
Numerators for basic and diluted net income per common unit:			
Net income (loss) attributable to Genesis Energy, L.P.	$96,319	$51,249	$(48,459)
Less: General partner's incentive distribution paid or to be paid for the period	—	—	(8,128)
Add: Expense allocable to our general partner	—	—	76,923
Subtotal	96,319	51,249	20,336
Less: General partner 2% ownership	—	—	(407)
Income available for common unitholders	$96,319	$51,249	$19,929
Denominator for basic and diluted per common unit	78,363	67,938	40,560
Basic and diluted net income per common unit	$1.23	$0.75	$0.49

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 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.

In July 2011, we issued 7,350,000 common units in a public offering. We received proceeds, net of underwriting discounts and offering costs, of $185 million from the offering. The proceeds were used to fund our acquisition of the black oil barge transportation business of FMT (see Note 3) and other corporate purposes, including the repayment of borrowings outstanding under our credit facility.
In November 2010, we issued 5,175,000 common units in a public offering in connection with the acquisition of a 50% equity interest in CHOPS. Our general partner also contributed capital of $2.5 million in November 2010 to maintain its 2% capital account. The new common units issued in 2012, 2011 and 2010 to the public for cash were as follows:

Period	Purchaser of Common Units	Units	Gross Unit Price	Issuance Value	GP Contributions	Costs	Net Proceeds
March 2012	Public	5,750	$30.80	$177,100	$—	$(7,679)	$169,421
July 2011	Public	7,350	$26.30	$193,305	$—	$(8,336)	$184,969
November 2010	Public	5,175	$23.58	$122,027	$2,490	$(5,680)	$118,837

During 2010, we recorded a non-cash contribution of $76.9 million from our general partner related to incentive compensation arrangements with our senior executives. As the purpose of these arrangements was to incentivize these individuals to grow the partnership, the expense was recognized as compensation by us and a capital contribution by our general partner. This amount relates to arrangements representing an equity interest in our general partner for which our general partner did not seek reimbursement under our partnership agreement.
12. Business Segment Information
Our operations consist of three operating segments:
- Pipeline Transportation – interstate, intrastate and offshore crude oil, and to a lesser extent, CO_2;

- 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 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.

Table of Contents

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 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.

	Pipeline Transportation	Refinery Services	Supply & Logistics	Total
Year Ended December 31, 2012				
Segment margin [a]	$96,539	$72,883	$92,911	$262,333
Capital expenditures [b]	$328,710	$2,692	$94,896	$426,298
Revenues:				
External customers	$61,706	$205,110	$3,803,241	$4,070,057
Intersegment [c]	14,584	(9,093)	(5,491)	—
Total revenues of reportable segments	$76,290	$196,017	$3,797,750	$4,070,057
Year Ended December 31, 2011				
Segment margin [a]	$67,908	$74,618	$59,975	$202,501
Capital expenditures [b]	$14,501	$1,846	$170,647	$186,994
Revenues:				
External customers	$50,391	$210,394	$2,828,884	$3,089,669
Intersegment [c]	11,799	(8,683)	(3,116)	—
Total revenues of reportable segments	$62,190	$201,711	$2,825,768	$3,089,669
Year Ended December 31, 2010				
Segment margin [a]	$48,305	$62,923	$38,336	$149,564
Capital expenditures [b]	$333,557	$1,433	$1,740	$336,730
Revenues:				
External customers	$45,367	$158,456	$1,897,501	$2,101,324
Intersegment [c]	10,285	(7,396)	(2,889)	—
Total revenues of reportable segments	$55,652	$151,060	$1,894,612	$2,101,324

Total assets by reportable segment were as follows:

	December 31, 2012	December 31, 2011	December 31, 2010
Pipeline transportation	$ 890,652	$ 594,728	$ 606,980
Refinery services	414,170	426,993	422,351
Supply and logistics	750,347	658,393	432,808
Other assets	54,495	50,730	44,596
Total consolidated assets	$ 2,109,664	$ 1,730,844	$ 1,506,735

Table of Contents

(a) A reconciliation of Segment Margin to income (loss) before income taxes for each year presented is as follows:

	Year Ended December 31,		
	2012	2011	2010
Segment margin	$262,333	$202,501	$149,564
Corporate general and administrative expenses	(38,372)	(31,685)	(110,058)
Depreciation, amortization and impairment	(61,166)	(62,190)	(53,569)
Interest expense	(40,921)	(35,767)	(22,924)
Distributable cash from equity investees in excess of equity in earnings	(24,464)	(16,681)	(2,284)
Non-cash items not included in segment margin	(5,280)	(1,531)	(4,479)
Cash payments from direct financing leases in excess of earnings	(5,016)	(4,615)	(4,203)
Income (loss) before income taxes	$87,114	$50,032	$(47,953)

(b) 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. Capital spending in our pipeline transportation segment included $63.7 million during the year ended December 31, 2012 representing capital contributions to our SEKCO equity investee to fund our share of the construction costs for its pipeline. During the same period, capital spending in our pipeline transportation segment also included $205.6 million for the acquisition of interests in several Gulf of Mexico pipelines. During 2012, capital spending in our supply and logistics segment also included $30.9 million for the purchase of barge assets.

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

Table of Contents

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,		
	2012	2011	2010 (1)
Revenues:			
Petroleum products sales to an affiliate of the Quintana Group (2)	$21,143	$20,888	$3,740
Sales of CO_2 to Sandhill Group, LLC (3)	2,905	2,481	2,706
Petroleum products sales to Davison family businesses (2)	1,344	1,207	1,081
Pipeline transportation and supply and logistics services provided to Denbury	—	—	3,059
Expenses:			
Marine operating fuel and expenses provided by an affiliate of the Quintana Group (2)	6,260	3,568	2,443
Amounts paid to our CEO in connection with the use of his aircraft	600	316	—
Operations, general and administrative services provided by our general partner (4)	—	—	47,035
Supply and logistics products and services provided by Denbury	—	—	373

(1) Affiliates of Denbury Resources, Inc. sold its interests in our general partner in February 2010. Transactions with Denbury are included in the table as a related party through that date.

(2) The Quintana Group, a private equity fund based in Houston, Texas owned 12% of our Class A common units and 74% of our Class B common units until October 5, 2012 when the Quintana Group monetized all of its remaining investment in us. Substantially in connection with that transaction, certain members of the Davison family, collectively, increased their investment in us to 17.2% of our Class A common units and 76.9% of our Class B common units. At December 31, 2012, certain members of the Davison family, collectively, owned 17% of our Class A common units and 76.9% of our Class B common units. Solely for financial statement purposes, we will continue to treat the Davison family and their affiliates as related parties.

(3) We own a 50% interest in Sandhill Group, LLC.

(4) Our general partner became a wholly-owned subsidiary in December 2010.

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, we believe that the terms of this arrangement are no worse than what we could have obtained in an arms-length transaction.

In July 2010, we acquired from TD Marine its 51% interest in DG Marine. TD Marine is owned by members of the Davison family.

Amounts due to and from Related Parties

At December 31, 2012, and 2011 Sandhill owed us $0.3 million and $0.2 million, respectively, for purchases of CO_2. At December 31, 2011, an affiliate of the Quintana Group owed us $1.9 million. We owed the affiliate $0.1 million December 31, 2011.

Financing

We guarantee 50% of Sandhill's outstanding credit facility loan. At December 31, 2012 and 2011, the total amount of Sandhill's obligation to the bank was $1.2 million and $1.7 million, respectively; therefore, our guarantee was for $0.6 million and $0.9 million for the respective periods.

As discussed in Note 11, our general partner made capital contributions in order to maintain its capital account totaling $2.5 million in 2010. In 2010, we recorded a capital contribution from our general partner of $76.9 million related to compensation recognized for our executive management team (see Note 15).

Table of Contents

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,		
	2012	2011	2010
(Increase) decrease in:			
Accounts receivable	$(34,299)	$(66,208)	$(41,648)
Inventories	14,074	(46,151)	(16,870)
Other current assets	(9,593)	(3,598)	(4,036)
Increase (decrease) in:			
Accounts payable	53,146	33,049	47,401
Accrued liabilities	(10,263)	15,977	9,666
Net changes in components of operating assets and liabilities	$13,065	$(66,931)	$(5,487)

Payments of interest and commitment fees, net of amounts capitalized, were $41.5 million, $32.9 million and $25.1 million during the years ended December 31, 2012, 2011 and 2010, respectively. We capitalized interest of $3.9 million during 2012 and $0.1 million for both 2011 and 2010.
During the years ended December 31, 2012 and 2011, we received tax refunds, net of amounts paid, of $0.3 million and $0.1 million, respectively. Cash paid for income taxes, net of amounts refunded, was $2.4 million during 2010.
At December 31, 2012, 2011 and 2010, we had incurred liabilities for fixed and intangible asset additions totaling $14.1 million, $2 million and $2.6 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” on 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 2012 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 2012, we granted 176,995 phantom units with tandem DERs at a weighted average grant fair value of $31.14 per unit. During 2011, we granted 151,916 phantom units with tandem DERs at a weighted average grant date fair value of $27.82 per unit. The phantom units granted during 2012 and 2011 were both service-based and performance-based awards. The service-based awards vest on the third anniversary of the date of grant. Between 50% and 150% of the number of performance-based phantom units awarded in 2011 and 2012 will vest on the third anniversary of the date of grant, if certain quarterly cash distribution per common unit targets are achieved in the fourth quarter of 2013 and 2014, 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 2010, we granted

62,927 phantom units that were service-based awards at a weighted average grant date fair value of $20.64 per unit. These phantom units will vest on the third anniversary of the date of grant. 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	Number of Phantom Units	Average Grant Date Fair Value	Total Value
Unvested at December 31, 2011	109,762	$23.36	$2,564	102,970	$28.19	$2,902
Granted	48,785	$30.52	1,489	128,210	$31.38	4,023
Forfeited	(1,787)	$29.04	(52)	(2,679)	$29.04	(78)
Settled	(30,548)	$24.94	(762)	—	$—	—
Unvested at December 31, 2012	126,212	$25.66	$3,239	228,501	$29.97	$6,847

At December 31, 2012, we estimated the unrecognized compensation cost of our phantom awards to be approximately $7.5 million to be recognized over a weighted average period of approximately two years. We recorded $6.7 million and $1.9 million of compensation expense for the years ended December 31, 2012 and 2011, respectively. Our liability for these awards totaled $7.2 million and $2 million at December 31, 2012 and 2011, respectively.

2007 Long Term Incentive Plan

As a result of the sale of our general partner in February 2010, all outstanding phantom units issued pursuant to our 2007 Long Term Incentive Plan vested. As a result of this acceleration of the vesting period, we recorded non-cash compensation expense of $0.5 million in the first quarter of 2010. In total, 123,857 phantom units vested. This expense is primarily included in general and administrative expenses. At December 31, 2012 and 2011, there were no awards outstanding under this plan.

Stock Appreciation Rights Plan

Our Stock Appreciation Rights Plan is administered by the G&C Committee, who 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.

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. Under accounting guidance, the liability is calculated using a fair value method that takes into consideration the expected future value of the rights at their expected exercise dates.

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:

Table of Contents

	Assumptions Used for Fair Value of Rights		
	December 31, 2012	December 31, 2011	December 31, 2010
Expected life of rights (in years)	Less than 1	0.00 - 3.41	0.00 - 4.41
Risk-free interest rate	0.00% - 0.07%	0.00% - 0.58%	0.12% - 1.73%
Expected unit price volatility	39.3%	40.6%	41.9%
Expected future distribution yield	5.00%	6.00%	6.00%

The following table reflects rights activity under our Stock Appreciation Rights Plan as of January 1, 2012, and changes during the year ended December 31, 2012:

	Stock Appreciation Rights	Weighted Average Strike Price	Weighted Average Contractual Remaining Term (Yrs)	Aggregate Intrinsic Value
Outstanding at December 31, 2011	662,484	$17.97		
Exercised during 2012	(264,060)	$18.85		
Forfeited or expired during 2012	(13,618)	$18.91		
Outstanding at December 31, 2012	384,806	$17.25	4.83	$7,099
Exercisable at December 31, 2012	351,051	$17.66	4.71	$6,332

The total intrinsic value of rights exercised during 2012, 2011 and 2010 was $3.3 million, $2.4 million and $1.3 million, respectively, which was paid in cash to the participants.

At December 31, 2012, there was less than $0.1 million of total unrecognized compensation cost related to rights that we expect will vest under the Stock Appreciation Rights Plan. This amount was calculated as the fair value at December 31, 2012 multiplied by those rights for which compensation cost has not been recognized, adjusted for estimated forfeitures. This unrecognized cost will be recalculated at each balance sheet date until the rights are exercised, forfeited or expire. For the awards outstanding at December 31, 2012, the remaining cost will be recognized in the first quarter of 2013.

We recorded compensation expense related to our stock appreciation rights of $4.5 million, $0.6 million and $5.2 million in 2012, 2011 and 2010, respectively.

Equity-Based Compensation Plan Expense

Equity-based compensation expense during the three years ended December 31, 2012 was as follows:

	Expense Related to Equity-Based Compensation Plans		
Consolidated Statement of Operations	2012	2011	2010
Supply and logistics operating costs	$3,038	$181	$2,611
Refinery services operating costs	1,427	226	833
Pipeline operating costs	247	135	575
General and administrative expenses	6,467	2,013	2,098
Total	$11,179	$2,555	$6,117

Series B Units

Pursuant to restricted unit agreements entered into with Genesis Energy, LLC, our general partner, on February 5, 2010, certain members of our management team received an aggregate of 767 Series B units in our general partner. These awards provided for the conversion of the Series B units into Series A units in our general partner on the seventh anniversary of the issuance date of the awards or at the time of certain events including a change in control of our general partner. As a result of our IDR Restructuring on December 28, 2010, the Series B units converted into Series A units. The Series A units were then exchanged for a total of 2,364,279 Class A Units and 827,484 Waiver

Units. See Note 11 for a discussion of our IDR Restructuring and our equity securities.

Table of Contents

Although the Series B Units represented an equity interest in our general partner and our general partner did not seek reimbursement under our partnership agreement for the value of these compensation arrangements, we recorded non-cash expense for the estimated fair value of the awards. For the year ended December 31, 2010, we recorded non-cash expense of $79.1 million related to these Series B awards with an offsetting entry to the capital account of our general partner. As the awards are fully-vested, no further compensation expense for these awards remains to be recorded.

Class B Membership Interests

As part of finalizing the compensation arrangements for our senior executives on December 31, 2008, our general partner awarded them an equity interest in our general partner as long-term incentive compensation. The Class B membership interests awarded to our senior executives were accounted for as liability awards under the guidance for equity-based compensation.

All of the Class B membership interests in our general partner held by our management team at December 31, 2009 were either (i) converted into Series A units in our general partner or (ii) redeemed by our general partner on February 5, 2010. In total, the value of the Series A units issued and cash payments made by our general partner to settle its obligations under the Class B membership interests and related deferred compensation totaled $14.9 million. This value, when combined with amounts previously paid to our management team during 2009 related to the Class B membership interests, resulted in total compensation expense of $15.4 million. Upon settlement by our general partner of these arrangements with our management team, we recorded a reduction in expense of $2.1 million in the first quarter of 2010.

Bonus Program

Bonuses under our bonus plan are paid at the discretion of the G&C Committee to our employees and executive officers. In 2012, 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 used to determine 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 reduction 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. At December 31, 2012, we accrued $7.9 million for estimated bonuses to be paid in March 2013. For 2011 and 2010, we paid bonuses totaling $6.6 million and $5.2 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 $3.4 million, $2.6 million and $2.7 million for the years ended December 31, 2012, 2011 and 2010, 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 $8.8 million, $8.1 million and $6.5 million in 2012, 2011 and 2010, 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 integrated and large independent energy companies with stable payment experience. The credit risk related to contracts which are traded on the NYMEX is limited due to daily margin requirements and other NYMEX requirements.

Table of Contents

We have established various procedures to manage our credit exposure, including initial credit approvals, credit limits, collateral requirements and rights of offset. Letters of credit, prepayments and guarantees are also utilized to limit credit risk to ensure that our established credit criteria are met.

During 2012, 2011 and 2010 our largest customer was Shell Oil Company, which accounted for 14%, 16% and 13% 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, 2012, we had the following outstanding derivative commodity futures and options 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)	316	199
Weighted average contract price per bbl	$88.35	$89.66
Crude oil LLS/WTI swap:		
Contract volumes (1,000 bbls)	100	—
Weighted average contract price per bbl	$17.25	$—
Heating oil futures:		
Contract volumes (1,000 bbls)	62	—
Weighted average contract price per gal	$3.02	$—
# 6 Fuel oil futures:		
Contract volumes (1,000 bbls)	765	160

Weighted average contract price per bbl	$92.37	$93.06
Crude oil options:		
Contract volumes (1,000 bbls)	325	85
Weighted average premium received	$1.61	$0.55

Table of Contents

Interest Rate Derivatives

During 2010, our DG Marine subsidiary utilized swap contracts with financial institutions to hedge interest payments for its outstanding debt. DG Marine expected these interest rate swap contracts to be highly effective in limiting its exposure to fluctuations in market interest rates; therefore, we designated these swap contracts as cash flow hedges under accounting guidance. The effective portion of the derivative represented the change in fair value of the hedge that offset the change in cash flows of the hedged item. The effective portion of the gain or loss in the fair value of these swap contracts was reported as a component of Accumulated Other Comprehensive Loss (AOCL) and was reclassified into future earnings contemporaneously, as interest expense associated with the underlying debt was recorded. In the third quarter of 2010, we settled the DG Marine interest rate swaps in connection with our acquisition of the 51% interest of DG Marine that we did not own (see Note 3).

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
Designated as hedges under accounting guidance:			
Crude oil futures contracts (fair value hedge)	Volatility in crude oil prices - effect on market value of inventory	Derivative is recorded in Other current assets (offset against margin deposits) and offsetting change in fair value of inventory is recorded in Inventories	Excess, if any, over effective portion of hedge is recorded in Supply and logistics costs - product costs Effective portion is offset in cost of sales against change in value of inventory being hedged
Interest rate swaps (cash flow hedge) (through July 2010)	Changes in interest rates	Not applicable	Expect hedge to fully offset hedged risk; no ineffectiveness recorded. Effective portion is recorded to AOCL and ultimately reclassified to Interest expense
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.

Table of Contents

The following tables reflect the estimated fair value gain (loss) position of our derivatives at December 31, 2012 and 2011:
Fair Value of Derivative Assets and Liabilities

	Consolidated Balance Sheets Location	Fair Value December 31, 2012	Fair Value December 31, 2011
Asset Derivatives:			
Commodity derivatives—futures and call options:			
Undesignated hedges	Current Assets - Other	758	306
Total asset derivatives		$758	$306
Liability Derivatives:			
Commodity derivatives—futures and call options:			
Undesignated hedges	Current Assets - Other	(3,357) [1]	(2,820) [1]
Total liability derivatives		$(3,357)	$(2,820)

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

Effect on Operating Results

	Amount of Loss Recognized in Income: Supply & Logistics Product Costs, Year Ended December 31, 2012	2011	2010	Interest Expense Reclassified from AOCL, Year Ended December 31, 2012	2011	2010	Other Comprehensive Loss Effective Portion, Year Ended December 31, 2012	2011	2010
Commodity derivatives—futures and call options:									
Contracts designated as hedges under accounting guidance	$—	$(173) [1]	$307 [1]	$—	$—	$—	$—	$—	$—
Contracts not considered hedges under accounting guidance	(2,388)	(17,419)	(4)	—	—	—	—		