HOLLY ENERGY PARTNERS LP
Form 10-K
February 25, 2015

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

FORM 10-K

(Mark One)
ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2014
OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to ____________
Commission File Number 1-32225

HOLLY ENERGY PARTNERS, L.P.
(Exact name of registrant as specified in its charter)

Delaware	20-0833098
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
2828 N. Harwood, Suite 1300 Dallas, Texas	75201-1507
(Address of principal executive offices)	(Zip Code)

(214) 871-3555
Registrant’s telephone number, including area code

Securities registered pursuant to Section 12(b) of the Act:
Common Limited Partner Units

Securities registered pursuant to 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 ý No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15 (d) of the Act. Yes ¨ No ý
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the 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 ý No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý

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 ý Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

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

The aggregate market value of common limited partner units held by non-affiliates of the registrant was approximately $1.2 billion on June 30, 2014, the last day of the registrant's most recently completed second fiscal quarter, based on the last sales price as quoted on the New York Stock Exchange on such date.

The number of the registrant’s outstanding common limited partners units at February 20, 2015 was 58,657,048.

DOCUMENTS INCORPORATED BY REFERENCE: None

TABLE OF CONTENTS

PART I

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains certain “forward-looking statements” within the meaning of the federal securities laws. All statements, other than statements of historical fact included in this Form 10-K, including, but not limited to, those under “Business”, “Risk Factors” and “Properties” in Items 1, 1A and 2 and “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in Item 7, are forward-looking statements. Forward looking statements use words such as “anticipate,” “project,” “expect,” “plan,” “goal,” “forecast,” “intend,” “should,” “would,” “could,” “may,” and similar expressions and statements regarding our plans and objectives for future operations. These statements are based on our beliefs and assumptions and those of our general partner using currently available information and expectations as of the date hereof, are not guarantees of future performance and involve certain risks and uncertainties. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give assurance that our expectations will prove to be correct. All statements concerning our expectations for future results of operations are based on forecasts for our existing operations and do not include the potential impact of any future acquisitions. Our forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. Certain factors could cause actual results to differ materially from results anticipated in the forward-looking statements. These factors include, but are not limited to:

- risks and uncertainties with respect to the actual quantities of petroleum products and crude oil shipped on our pipelines and/or terminalled, stored or throughput in our terminals;
- the economic viability of HollyFrontier Corporation, Alon USA, Inc. and our other customers;
- the demand for refined petroleum products in markets we serve;
- our ability to purchase and integrate future acquired operations;
- our ability to complete previously announced or contemplated acquisitions;
- the availability and cost of additional debt and equity financing;
- the possibility of reductions in production or shutdowns at refineries utilizing our pipeline and terminal facilities;
- the effects of current and future government regulations and policies;
- our operational efficiency in carrying out routine operations and capital construction projects;
- the possibility of terrorist attacks and the consequences of any such attacks;
- general economic conditions; and
- other financial, operational and legal risks and uncertainties detailed from time to time in our Securities and Exchange Commission filings.

Cautionary statements identifying important factors that could cause actual results to differ materially from our expectations are set forth in this Form 10-K, including without limitation, the forward-looking statements that are referred to above. When considering forward-looking statements, you should keep in mind the known material risk factors and other cautionary statements set forth in this Form 10-K under “Risk Factors” in Item 1A. All forward-looking statements included in this Form 10-K and all subsequent written or oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements. The forward-looking statements speak only as of the date made and, other than as required by law, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

INDEX TO DEFINED TERMS AND NAMES

The following terms and names that appear in this form 10-K are defined on the following pages:

- 4 -

Item 1. Business

OVERVIEW

Holly Energy Partners, L.P. ("HEP") is a Delaware limited partnership engaged principally in the business of operating a system of petroleum product and crude pipelines, storage tanks, distribution terminals and loading rack facilities in West Texas, New Mexico, Utah, Nevada, Oklahoma, Wyoming, Kansas, Arizona, Idaho and Washington. We were formed in Delaware in 2004 and maintain our principal corporate offices at 2828 N. Harwood, Suite 1300, Dallas, Texas 75201-1507. Our telephone number is 214-871-3555 and our internet website address is www.hollyenergy.com. The information contained on our website does not constitute part of this Annual Report on Form 10-K. A copy of this Annual Report on Form 10-K will be provided without charge upon written request to the Vice President, Investor Relations at the above address. A direct link to our filings at the U.S. Securities and Exchange Commission ("SEC") website is available on our website on the Investors page. Also available on our website are copies of our Governance Guidelines, Audit Committee Charter, Compensation Committee Charter, and Code of Business Conduct and Ethics, all of which will be provided without charge upon written request to the Vice President, Investor Relations at the above address. In this document, the words "we," "our," "ours" and "us" refer to HEP and its consolidated subsidiaries or to HEP or an individual subsidiary and not to any other person. "HFC" refers to HollyFrontier Corporation and its subsidiaries, other than HEP and its subsidiaries and other than Holly Logistic Services, L.L.C. ("HLS"), a subsidiary of HollyFrontier Corporation that is the general partner of the general partner of HEP and manages HEP.

We own and operate petroleum product and crude pipelines and terminal, tankage and loading rack facilities that support HFC's refining and marketing operations in the Mid-Continent, Southwest and Rocky Mountain regions of the United States and Alon USA, Inc.'s ("Alon") refinery in Big Spring, Texas. HFC currently owns a 39% interest in us, including the 2% general partner interest. Additionally, we own a 75% interest in UNEV Pipeline, LLC ("UNEV"), which owns a 427-mile, 12-inch refined products pipeline running from Woods Cross, Utah to Las Vegas, Nevada (the "UNEV Pipeline"), product terminals near Cedar City, Utah and Las Vegas, Nevada and related assets; and a 25% joint venture interest in a 95-mile intrastate crude oil pipeline system (the "SLC Pipeline") that serves refineries in the Salt Lake City, Utah area.

We generate revenues by charging tariffs for transporting petroleum products and crude oil through our pipelines, by charging fees for terminalling and storing refined products and other hydrocarbons, and providing other services at our storage tanks and terminals. We do not take ownership of products that we transport, terminal or store, and therefore, we are not directly exposed to changes in commodity prices.

Our assets include:

Pipelines:

- approximately 810 miles of refined product pipelines, including 340 miles of leased pipelines, that transport gasoline, diesel and jet fuel principally from HFC's Navajo refinery in New Mexico to its customers in the metropolitan and rural areas of Texas, New Mexico, Arizona, Utah and northern Mexico;
- approximately 510 miles of refined product pipelines that transport refined products from Alon's Big Spring refinery in Texas to its customers in Texas and Oklahoma;
- three 65-mile intermediate pipelines that transport intermediate feedstocks and crude oil from HFC's Navajo refinery crude oil distillation and vacuum facilities in Lovington, New Mexico to its petroleum refinery facilities in Artesia, New Mexico;
- approximately 910 miles of crude oil trunk, gathering and connection pipelines located in West Texas, New Mexico and Oklahoma that deliver crude oil to HFC's Navajo refinery;
- approximately 8 miles of refined product pipelines that support HFC's Woods Cross refinery located near Salt Lake City, Utah;
- gasoline and diesel connecting pipelines located at HFC's Tulsa East refinery facility;
- five intermediate product and gas pipelines between HFC's Tulsa East and West refinery facilities;
- crude receiving assets located at HFC's Cheyenne refinery;
- a 75% interest in the UNEV Pipeline, a 427-mile refined products pipeline running from Woods Cross, Utah to Las Vegas, Nevada; and
-

a 25% joint venture interest in the SLC Pipeline, a 95-mile intrastate crude oil pipeline system that transports crude oil into the Salt Lake City, Utah area from the Utah terminus of the Frontier Pipeline, as well as crude oil flowing from Wyoming and Utah via Plains All American Pipeline, L. P.'s ("Plains") Rocky Mountain Pipeline.

Refined Product Terminals and Refinery Tankage:

- four refined product terminals located in El Paso, Texas; Moriarty and Bloomfield, New Mexico; and Tucson, Arizona, with an aggregate capacity of approximately 1,200,000 barrels, that are integrated with our refined product pipeline system that serves HFC’s Navajo refinery;
- one refined product terminal located in Spokane, Washington, with a capacity of approximately 400,000 barrels, that serves third-party common carrier pipelines;
- one refined product terminal near Mountain Home, Idaho with a capacity of approximately 120,000 barrels, that serves a nearby United States Air Force Base;
- two refined product terminals, located in Wichita Falls and Abilene, Texas, and one tank farm in Orla, Texas with aggregate capacity of approximately 500,000 barrels, that are integrated with our refined product pipelines that serve Alon’s Big Spring refinery;
- a refined product loading rack facility at each of HFC’s refineries, heavy product / asphalt loading rack facilities at HFC’s Navajo refinery Lovington facility, Tulsa refinery East facility and the Cheyenne refinery, liquefied petroleum gas (“LPG”) loading rack facilities at HFC’s Tulsa refinery West facility, Cheyenne refinery and El Dorado refinery, lube oil loading racks at HFC’s Tulsa refinery West facility and crude oil Leased Automatic Custody Transfer (“LACT”) units located at HFC’s Cheyenne refinery;
- on-site crude oil tankage at HFC’s Navajo, Woods Cross, Tulsa and Cheyenne refineries having an aggregate storage capacity of approximately 1,300,000 barrels;
- on-site refined and intermediate product tankage at HFC’s Tulsa, Cheyenne and El Dorado refineries having an aggregate storage capacity of approximately 8,100,000 barrels; and
- a 75% interest in UNEV Pipeline's product terminals near Cedar City, Utah and Las Vegas, Nevada with an aggregate capacity of approximately 615,000 barrels.

We have a long-term strategic relationship with HFC. Our growth plan is to continue to pursue purchases of logistic assets at HFC's existing refining locations in New Mexico, Utah, Oklahoma, Kansas and Wyoming. We will also work with HFC on logistic asset acquisitions in conjunction with HFC’s refinery acquisition strategies. Furthermore, we will continue to pursue third-party logistic asset acquisitions that are accretive to our unitholders and increase the diversity of our revenues.

In March 2014, we redeemed the $150 million aggregate principal amount of 8.25% senior notes (the "8.25% Senior Notes")maturing March 2018 at a redemption cost of $156.2 million, at which time we recognized a $7.7 million early extinguishment loss consisting of a $6.2 million debt redemption premium and unamortized discount and financing costs of $1.5 million. We funded the redemption with borrowings under our Credit Agreement.

2012 Acquisition

UNEV Pipeline Interest Acquisition

On July 12, 2012, we acquired from HFC a 75% interest in UNEV. We paid consideration consisting of $260.9 million in cash and 2,059,800 of our common units. Also under the terms of the transaction, we issued to HFC a Class B unit comprising a noncontrolling equity interest in a wholly-owned subsidiary that entitles HFC to an interest in our share of annual UNEV earnings before interest, income taxes, depreciation, and amortization above $30 million beginning July 1, 2016 and ending in June 2032, subject to certain limitations. Contemporaneously with this transaction, HFC (our general partner) agreed to forego its right to incentive distributions of up to $1.25 million per quarter over twelve consecutive quarterly periods following the close of the transaction and up to an additional four quarters in certain circumstances. In connection with the transaction, we entered into 15-year throughput agreements with shippers containing minimum annual revenue commitments to us of $27 million.

Agreements with HFC and Alon

We serve HFC’s refineries under long-term pipeline and terminal, tankage and throughput agreements expiring from 2019 to 2026. Under these agreements, HFC agreed to transport, store and throughput volumes of refined product and crude oil on our pipelines and terminal, tankage and loading rack facilities that result in minimum annual payments to us. These minimum annual payments or revenues are subject to annual tariff rate adjustments on July 1, based on the Producer Price Index (“PPI”) or Federal Energy Regulatory Commission (“FERC”) index. As of December 31, 2014, these agreements with HFC will result in minimum payments to us of $231.6 million.

If HFC fails to meet its minimum volume commitments under the agreements in any quarter, it will be required to pay us in cash the amount of any shortfall by the last day of the month following the end of the quarter. Under certain of the agreements, a shortfall payment may be applied as a credit in the following four quarters after minimum obligations are met.

We have a pipelines and terminals agreement with Alon expiring in 2020 under which Alon has agreed to transport on our pipelines and throughput through our terminals volumes of refined products that result in a minimum level of annual revenue that also is subject to annual tariff rate adjustments. Also, we have a capacity lease agreement under which we lease Alon space on our Orla to El Paso pipeline for the shipment of refined product. The terms under this lease agreement expire beginning in 2018 through 2022. As of December 31, 2014, these agreements with Alon will result in minimum annualized payments to us of $32.1 million.

A significant reduction in revenues under these agreements could have a material adverse effect on our results of operations.

Furthermore, if new laws or regulations that affect terminals or pipelines are enacted that require us to make substantial and unanticipated capital expenditures at the pipelines or terminals, we will have the right after we have made efforts to mitigate their effects to negotiate a monthly surcharge on HFC for the use of the terminals or to file for an increased tariff rate for use of the pipelines to cover HFC’s pro rata portion of the cost of complying with these laws or regulations including a reasonable rate of return. In such instances, we will negotiate in good faith with HFC to agree on the level of the monthly surcharge or increased tariff rate.

For additional information regarding our significant customers, see Note 9 to the Consolidated Financial Statements included in Item 8 of Part II of this Form 10-K.

Omnibus Agreement

Under certain provisions of an omnibus agreement we have with HFC (the “Omnibus Agreement”), we pay HFC an annual administrative fee ($2.3 million in 2014 and currently $2.4 million) for the provision by HFC of various general and administrative services to us. This fee includes expenses incurred by HFC to perform centralized corporate functions, such as executive management, legal, accounting, treasury, information technology and other corporate services, including the administration of employee benefit plans. This fee does not include the salaries of personnel employed by HFC who perform services for us on behalf of HLS or the cost of their employee benefits, such as 401(k), pension and health insurance benefits, which are separately charged to us by HFC. We also reimburse HFC for direct expenses they incur on our behalf. In addition, we also pay for our own direct general and administrative costs, including costs relating to operating as a separate publicly held entity, such as costs for preparation of partners’ K-1 tax information, SEC filings, investor relations, directors’ compensation, directors’ and officers’ insurance and registrar and transfer agent fees.

Under HLS’s secondment arrangement with HFC, effective January 1, 2015, certain employees of HFC are seconded to HLS, the general partner of our general partner, to provide operational and maintenance services with respect to certain pipelines and terminals at the Cheyenne and El Dorado refineries, including routine operational and maintenance activities. During their period of secondment, the seconded employees are under the management and supervision of HLS. HLS reimburses HFC for our benefit for the cost of the seconded employees, including their wages and benefits, based on the percentage of the employee’s time spent working for HLS.

CAPITAL REQUIREMENTS

Our pipeline and terminalling operations are capital intensive, requiring investments to maintain, expand, upgrade or enhance existing operations and to meet environmental and operational regulations. Our capital requirements have consisted of, and are expected to continue to consist of, maintenance capital expenditures and expansion capital expenditures. “Maintenance capital expenditures” represent capital expenditures to replace partially or fully depreciated assets to maintain the operating capacity of existing assets. Maintenance capital expenditures include expenditures required to maintain equipment reliability, tankage and pipeline integrity, safety and to address environmental regulations. “Expansion capital expenditures” represent capital expenditures to expand the operating capacity of existing or new assets, whether through construction or acquisition. Expansion capital expenditures include expenditures to acquire assets, to grow our business and to expand existing facilities, such as projects that increase throughput capacity on our pipelines and in our terminals. Repair and maintenance expenses associated with existing assets that are minor in nature and do not extend the useful life of existing assets are charged to operating expenses as incurred.

Each year the board of directors of HLS, approves our annual capital budget, which specifies capital projects that our management is authorized to undertake. Additionally, at times when conditions warrant or as new opportunities arise, additional projects may be approved. The funds allocated for a particular capital project may be expended over a period in excess of a year, depending on the time required to complete the project. Therefore, our planned capital expenditures for a given year consist of expenditures approved for capital projects included in the current year's capital budget as well as, in certain cases, expenditures approved for capital projects in capital budgets for prior years. The 2015 capital budget is comprised of $9.7 million for maintenance capital expenditures and $77.7 million for expansion capital expenditures. We expect the majority of the expansion capital budget to be invested in crude storage for HFC's El Dorado refinery, product distribution enhancements, new storage tanks, and an additional UNEV origin connection. In addition to our capital budget, we may spend funds periodically to perform capital upgrades or additions to our assets where a customer reimburses us for such costs. The upgrades or additions would generally benefit the customer over the remaining life of the related service agreements.

We substantially completed the expansion of our crude oil transportation system in southeastern New Mexico in the third quarter of 2014 in response to increased crude oil production in the area. The expansion provides shippers with additional pipeline takeaway capacity to either common carrier pipeline stations for transportation to major crude oil markets or to HFC's New Mexico refining facilities. To complete the project, we converted an existing refined products pipeline to crude oil service, constructed several new pipeline segments, expanded an existing pipeline, and built new truck unloading stations and crude storage capacity. Excluding the value of the existing pipeline converted, total capital expenditures were approximately $50 million. HFC has contracted to reimburse us for the increase over the original budget range of $35 million to $40 million over a five year period through an additional fee on shipped volumes. We estimate the project will provide increased capacity of up to 100,000 barrels per day ("bpd") across the system.

UNEV completed a project to enhance its product terminal in Las Vegas, Nevada in the third quarter of 2014 with total capital expenditures of approximately $15 million.

We have announced that we are evaluating the potential construction of several new tanks at HFC’s El Dorado Refinery as well as additional pipeline connections that could increase the refinery’s crude flexibility. As this potential project is still under consideration, the HLS board has not yet approved a capital budget for such project. We have received engineering estimates for this potential project. Alternatively, we are evaluating the potential purchase of existing tanks.

We expect that our currently planned sustaining and maintenance capital expenditures, as well as expenditures for acquisitions and capital development projects, will be funded with cash generated by operations, the sale of additional limited partner common units, the issuance of debt securities and advances under our Credit Agreement, or a combination thereof. With volatility and uncertainty at times in the credit and equity markets, there may be limits on our ability to issue new debt or equity financing. Additionally, due to pricing movements in the debt and equity markets, we may not be able to issue new debt and equity securities at acceptable pricing. Without additional capital beyond amounts available under the Credit Agreement, our ability to obtain funds for some of these capital projects may be limited.

Under the terms of the transaction to acquire HFC's 75% interest in UNEV, we issued to HFC a Class B unit comprising a noncontrolling equity interest in a wholly-owned subsidiary subject to redemption to the extent that HFC is entitled to a 50% interest in our share of annual UNEV earnings before interest, income taxes, depreciation and amortization above $30 million beginning July 1, 2016, and ending in June 2032, subject to certain limitations.

SAFETY AND MAINTENANCE

Many of our pipelines are subject to regulation by the Pipeline and Hazardous Materials Safety Administration (“PHMSA”) of the DOT. PHMSA has promulgated regulations governing, among other things, maximum operating pressures, pipeline patrols and leak surveys, minimum depth requirements, and emergency procedures, as well as other matters intended to prevent accidents and failures. Additionally, PHMSA has promulgated regulations requiring pipeline operators to develop and implement integrity management programs for certain pipelines that, in the event of a pipeline leak or rupture, could affect “high consequence areas,” which are areas where a release could have the most significant adverse consequences, including high-population areas, certain drinking water sources and unusually sensitive ecological areas. We believe that our pipeline operations are in substantial compliance with requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, future compliance could result in increased costs.

In addition, many states have adopted regulations, similar to existing PHMSA regulations, for certain intrastate pipelines. For example, Texas has developed regulatory programs that largely parallel the federal regulatory scheme and impose additional requirements for certain pipelines.

We perform preventive and normal maintenance on all of our pipeline systems and make repairs and replacements when necessary or appropriate. We also conduct routine and required inspections of our pipelines and other assets as required by regulations. We inject corrosion inhibitors into our mainlines to help control internal corrosion. External coatings and impressed current cathodic protection systems are used to protect against external corrosion. We regularly monitor, test and record the effectiveness of these corrosion-inhibiting systems. We monitor the structural integrity of covered segments of our pipeline systems through a program of periodic internal inspections using both "dent pigs" and electronic "smart pigs", as well as hydrostatic testing that conforms to federal standards. We follow these inspections with a review of the data, and we make repairs as necessary to ensure the integrity of the pipeline. We have initiated a risk-based approach to prioritizing the pipeline segments for future smart pig runs or other approved integrity testing methods. We believe this approach will allow the pipelines that have the greatest risk potential to receive the highest priority in being scheduled for inspections or pressure tests for integrity. We believe our inspection process substantially complies with all applicable regulatory requirements. Nonetheless, the adoption of new or amended regulations or the reinterpretation of existing laws and regulations by PHMSA or the states that result in more stringent or costly pipeline integrity management or safety standards could possibly have a substantial effect on us and similarly situated midstream operators.

Maintenance facilities containing equipment for pipe repairs, spare parts, and trained response personnel are located along the pipelines. Employees participate in simulated spill deployment exercises on a regular basis. Also they participate in actual spill response boom deployment exercises in planned spill scenarios in accordance with Oil Pollution Act of 1990 requirements. We believe that all of our pipelines have been constructed and are maintained in all material respects in accordance with applicable federal and state laws, the regulations prescribed by PHMSA, standards prescribed by the American Petroleum Institute and accepted industry practice.

At our terminals, tanks designed for gasoline storage are equipped with internal or external floating roofs that minimize emissions and prevent potentially flammable vapor accumulation between fluid levels and the roof of the tank. Our terminal facilities have facility response plans, spill prevention and control plans, and other plans and programs to respond to emergencies.

Many of our terminal loading racks are protected with water deluge systems activated by either heat sensors or an emergency switch. Several of our terminals are also protected by foam systems that are activated in case of fire. All of our terminals are subject to participation in a comprehensive environmental management program to assure compliance with applicable air, solid waste, and wastewater regulations.

COMPETITION

As a result of our physical integration with HFC's refineries, our contractual relationship with HFC under the Omnibus Agreement and the HFC pipelines and terminals, tankage and throughput agreements, we believe that we will not face significant competition for barrels of refined products transported from HFC's refineries, particularly during the terms of our long-term transportation agreements with HFC expiring in 2019 through 2026. Additionally, under our throughput agreement with Alon expiring in 2020, we believe that we will not face significant competition for those barrels of refined products we transport from Alon's Big Spring refinery.

However, we do face competition from other pipelines that may be able to supply the end-user markets of HFC or Alon with refined products on a more competitive basis. Additionally, if HFC's wholesale customers reduced their purchases of refined products due to the increased availability of cheaper product from other suppliers or for other reasons, the volumes transported through our pipelines could be reduced, which, subject to the minimum revenue commitments, could cause a decrease in cash and revenues generated from our operations.

The petroleum refining business is highly competitive. Among HFC's competitors are some of the world's largest integrated petroleum companies, which have their own crude oil supplies and distribution and marketing systems. HFC competes with independent refiners as well. Competition in particular geographic areas is affected primarily by the amounts of refined products produced by refineries located in such areas and by the availability of refined products and the cost of transportation to such areas from refineries located outside those areas.

In addition, we face competition from trucks that deliver product in a number of areas we serve. Although their costs may not be competitive for longer hauls or large volume shipments, trucks compete effectively for incremental and

marginal volumes in many areas we serve. The availability of truck transportation places some competitive constraints on us.
Historically, the significant majority of the throughput at our terminal facilities has come from HFC, with the exception of third-party receipts at the Spokane terminal, Alon volumes at El Paso, and the Abilene and Wichita Falls terminals that serve Alon's Big Springs refinery.
Our ten refined product terminals compete with other independent terminal operators as well as integrated oil companies based on terminal location, price, versatility and services provided. Our competition primarily comes from integrated petroleum

companies, refining and marketing companies, independent terminal companies and distribution companies with marketing and trading arms.

RATE REGULATION

Some of our existing pipelines are subject to rate regulation by the FERC under the Interstate Commerce Act. The Interstate Commerce Act requires that tariff rates for oil pipelines, a category that includes crude oil and petroleum product pipelines, be just and reasonable and not unduly discriminatory. The Interstate Commerce Act permits challenges to rates that are already on file and in effect by complaint. A successful challenge under a complaint may result in the complainant obtaining damages or reparations for up to two years prior to the date the complaint was filed. The Interstate Commerce Act also permits challenges to a proposed new or changed rate by a protest. A successful challenge under a protest may result in the protestant obtaining refunds or reparations from the date the proposed new or changed rate becomes effective. In either challenge process, the third party must be able to show it has a substantial economic interest in those rates to proceed. The FERC generally has not investigated interstate rates on its own initiative but will likely become a party to any proceedings when the rates receive either a complaint or a protest. However, the FERC is not prohibited from bringing an interstate rate under investigation without a third-party intervention.

While the FERC regulates the rates for interstate shipments on our refined product pipelines, the New Mexico Public Regulation Commission regulates the rates for intrastate shipments in New Mexico, the Texas Railroad Commission regulates the rates for intrastate shipments in Texas, the Oklahoma Corporation Commission regulates the rates for intrastate shipments in Oklahoma and the Idaho Public Utilities Commission regulates the rates for intrastate shipments in Idaho. State commissions have generally not been aggressive in regulating common carrier pipelines and generally have not investigated the rates or practices of petroleum pipelines in the absence of shipper complaints, and we do not believe the intrastate tariffs now in effect are likely to be challenged. However, a state regulatory commission could investigate our rates if such a challenge were filed.

ENVIRONMENTAL REGULATION AND REMEDIATION

Our operation of pipelines, terminals, and associated facilities in connection with the storage and transportation of refined products is subject to stringent and complex federal, state, and local laws and regulations governing the discharge of materials into the environment, or otherwise relating to the protection of the environment. As with the industry generally, compliance with existing and anticipated laws and regulations increases our overall cost of business, including our capital costs to construct, maintain, and upgrade equipment and facilities. Although these laws and regulations affect our maintenance capital expenditures and net income, we believe that they do not affect our competitive position in that the operations of our competitors are similarly affected. We believe that our operations are in substantial compliance with applicable environmental laws and regulations. However, these laws and regulations, and the interpretation or enforcement thereof, are subject to frequent change by regulatory authorities, and we are unable to predict the ongoing cost to us of complying with these laws and regulations or the future impact of these laws and regulations on our operations. Violation of environmental laws, regulations, and permits can result in the imposition of significant administrative, civil and criminal penalties, injunctions, and construction bans or delays. A discharge of hydrocarbons or hazardous substances into the environment could, to the extent the event is not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and claims made by employees, neighboring landowners and other third parties for personal injury and property damage.

Contamination resulting from spills of refined products and crude oil is not unusual within the petroleum pipeline industry. Historic spills along our existing pipelines and terminals as a result of past operations have resulted in contamination of the environment, including soils and groundwater. Site conditions, including soils and groundwater, are being evaluated at a few of our properties where operations may have resulted in releases of hydrocarbons and other wastes, none of which we believe will have a significant effect on our operations since the remediation of such releases would be covered under environmental indemnification agreements. For example, we have an environmental agreement with Alon with respect to pre-closing environmental costs and liabilities relating to the pipelines and terminals acquired from Alon in 2005, under which Alon will indemnify us subject to certain monetary and time limitations. In addition, under the Omnibus Agreement and certain transportation agreements and purchase agreements with HFC, HFC has agreed to indemnify us, subject to certain monetary and time limitations, for environmental noncompliance and remediation liabilities associated with certain assets transferred to us from HFC and occurring or existing prior to the date of such transfers. There are environmental remediation projects currently in progress that relate to certain assets acquired from HFC. Certain of these projects were underway prior to our purchase and represent liabilities of HFC for future remediation activities retained by HFC. Additionally, as of December 31, 2014, we have an accrual of $5.2 million that relates to environmental clean-up projects for which we have assumed liability or for which the indemnity provided for by HFC has expired or will expire. The remaining projects, including assessment and monitoring activities, are covered under the HFC environmental indemnification discussed above and represent liabilities of HFC.

We may experience future releases into the environment from our pipelines and terminals or discover historical releases that were previously unidentified or not assessed. Although we maintain an extensive inspection and audit program designed, as applicable, to prevent, detect and address these releases promptly, damages and liabilities incurred due to any future environmental releases from our assets have the potential to substantially affect our business.

EMPLOYEES

Neither we nor our general partner has employees. Direct support for our operations is provided by HLS, which utilizes 273 people employed by HFC dedicated to performing services for us. We reimburse HFC for direct expenses that HFC or its affiliates incurs on our behalf for these employees. HFC considers its employee relations to be good. Under HLS's secondment arrangement with HFC, certain employees of HFC are seconded to HLS to provide operational and maintenance services for certain of our pipelines and tankage assets at the El Dorado and Cheyenne refineries, and HLS reimburses HFC for its prorated portion of the wages, benefits, and other costs of these employees for our benefit.

Several of the seconded employees at the El Dorado and Cheyenne refineries are represented by the United Steelworkers Union. In early February 2015, HFC received communications from the United Steelworkers Union representing employees at the El Dorado refinery of its intention to commence a work stoppage in early May 2015 and could receive a similar communication from the United Steelworkers Union representing employees at the Cheyenne refinery. HFC has plans allowing for the continued operations of both refineries in the event the union does commence a work stoppage and believes such plans are adequate to allow continued operations of both refineries as well as support for our operations provided by the seconded employees.

Item 1A. Risk Factors

Investing in us involves a degree of risk, including the risks described below. Our operating results have been, and will continue to be, affected by a wide variety of risk factors, many of which are beyond our control, that could have adverse effects on profitability during any particular period. You should consider the following risk factors carefully together with all of the other information included in this Annual Report on Form 10-K, including the financial statements and related notes, when deciding to invest in us. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may also materially and adversely affect our business operations. If any of the following risks were to actually occur, our business, financial condition, results of operations or treatment of unitholders could be materially and adversely affected.

The headings provided in this Item 1A. are for convenience and reference purposes only and shall not affect or limit the extent or interpretation of the risk factors.

RISKS RELATED TO OUR BUSINESS

If we are unable to generate sufficient cash flow, our ability to pay quarterly distributions to our common unitholders at current levels or to increase our quarterly distributions in the future could be impaired materially.

Our ability to pay quarterly distributions depends primarily on cash flow (including cash flow from operations, financial reserves and credit facilities) and not solely on profitability, which is affected by non-cash items. As a result, we may pay cash distributions during periods of losses and may be unable to pay cash distributions during periods of income. Our ability to generate sufficient cash from operations is largely dependent on our ability to manage our business successfully which may also be affected by economic, financial, competitive, regulatory, and other factors that are beyond our control. Because the cash we generate from operations will fluctuate from quarter to quarter, quarterly distributions may also fluctuate from quarter to quarter.

We depend on HFC and particularly its Navajo refinery for a majority of our revenues; if those revenues were significantly reduced or if HFC's financial condition materially deteriorated, there would be a material adverse effect on our results of operations.

For the year ended December 31, 2014, HFC accounted for 79% of the revenues of our petroleum product and crude pipelines and 89% of the revenues of our terminals, tankage, and truck loading racks. We expect to continue to derive a majority of our revenues from HFC for the foreseeable future. If HFC satisfies only its minimum obligations under the long-term pipeline and terminal, tankage and throughput agreements that it has with us or is unable to meet its minimum annual payment commitment for any reason, including due to prolonged downtime or a shutdown at HFC's refineries, our revenues and cash flow would decline.

Any significant reduction in production at the Navajo refinery could reduce throughput in our pipelines and terminals, resulting in materially lower levels of revenues and cash flow for the duration of the shutdown. For the year ended December 31, 2014, production from the Navajo refinery accounted for 79.0% of the throughput volumes transported by our refined product and crude pipelines. The Navajo refinery also received 98% of the petroleum products shipped on our New Mexico intermediate pipelines. Operations at any of HFC's refineries could be partially or completely shut down, temporarily or permanently, as the result of:

- competition from other refineries and pipelines that may be able to supply the refinery's end-user markets on a more cost-effective basis;
- operational problems such as catastrophic events at the refinery, labor difficulties, environmental proceedings or other litigation that cause a stoppage of all or a portion of the operations at the refinery;
- planned maintenance or capital projects;
- increasingly stringent environmental laws and regulations, such as the U.S. Environmental Protection Agency's gasoline and diesel sulfur control requirements that limit the concentration of sulfur in motor gasoline and diesel fuel for both on-road and non-road usage as well as various state and federal emission requirements that may affect the refinery itself and potential future climate change regulations;
- an inability to obtain crude oil for the refinery at competitive prices; or
- a general reduction in demand for refined products in the area due to:
  - a local or national recession or other adverse economic condition that results in lower spending by businesses and consumers on gasoline and diesel fuel;
  - higher gasoline prices due to higher crude oil costs, higher taxes or stricter environmental laws or regulations; or
  - a shift by consumers to more fuel-efficient or alternative fuel vehicles or an increase in fuel economy, whether as a result of technological advances by manufacturers, legislation either mandating or encouraging higher fuel economy or the use of alternative fuel or otherwise.

The effect on us of any shutdown would depend on the length of the shutdown and the extent of the refinery operations affected by the shutdown. We have no control over the factors that may lead to a shutdown or the measures HFC may take in response to a shutdown. HFC makes all decisions at each of its refineries concerning levels of production, regulatory compliance, refinery turnarounds (planned shutdowns of individual process units within the refinery to perform major maintenance activities), labor relations, environmental remediation, emission control and capital expenditures and is responsible for all related costs. HFC is under no contractual obligation to us to maintain operations at its refineries.

Furthermore, HFC's obligations under the long-term pipeline and terminal, tankage and throughput agreements with us would be temporarily suspended during the occurrence of a force majeure event that renders performance impossible with respect to an asset for at least 30 days. If such an event were to continue for a year, we or HFC could terminate the agreements. The occurrence of any of these events could reduce our revenues and cash flows.

We depend on Alon and particularly its Big Spring refinery for a portion of our revenues; if those revenues were significantly reduced, there could be a material adverse effect on our results of operations.

For the year ended December 31, 2014, Alon accounted for 10% of the combined revenues of our petroleum product and crude pipelines and of our terminals and truck loading racks, including revenues we received from Alon under a capacity lease agreement. If Alon satisfies only its minimum obligations under the long-term pipeline and terminal, tankage and throughput agreements that it has with us or is unable to meet its minimum annual payment commitment for any reason, including due to prolonged downtime or a shutdown at Alon’s refineries, our revenues and cash flow would decline.

A decline in production at Alon's Big Spring refinery could reduce materially the volume of refined products we transport and terminal for Alon and, as a result, our revenues could be materially adversely affected. The Big Spring refinery could partially or completely shut down its operations, temporarily or permanently, due to factors affecting its ability to produce refined products or for planned maintenance or capital projects. Such factors would include the factors discussed above under the discussion of risk with respect to the Navajo refinery.

The effect on us of any shutdown depends on the length of the shutdown and the extent of the refinery operations affected. We have no control over the factors that may lead to a shutdown or the measures Alon may take in response to a shutdown. Alon makes all decisions and is responsible for all costs at the Big Spring refinery concerning levels of production, regulatory compliance, refinery turnarounds, labor relations, environmental remediation, emission control and capital expenditures.

In addition, under our throughput agreement with Alon, if we are unable to transport or terminal refined products that Alon is prepared to ship, then Alon has the right to reduce its minimum volume commitment to us during the period of interruption. If a force majeure event occurs, we or Alon could terminate the Alon pipelines and terminals agreement after the expiration of certain time periods. The occurrence of any of these events could reduce our revenues and cash flows.

Due to our lack of asset diversification, adverse developments in our businesses could materially and adversely affect our financial condition, results of operations, or cash flows.

We rely exclusively on the revenues generated from our business. Due to our lack of asset diversification, especially a large concentration of pipeline assets serving the Navajo refinery, an adverse development in our business could have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets.

Our leverage may limit our ability to borrow additional funds, comply with the terms of our indebtedness or capitalize on business opportunities.

As of December 31, 2014, the principal amount of our total outstanding debt was $871.0 million. Our results of operations, cash flows and financial position could be adversely affected by significant increases in interest rates above current levels. Various limitations in our Credit Agreement and the indenture for our 6.50% senior notes due 2020 (the “6.5% Senior Notes”) may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

Our leverage could have important consequences. We require substantial cash flow to meet our payment obligations with respect to our indebtedness. Our ability to make scheduled payments, to refinance our obligations with respect to our indebtedness or our ability to obtain additional financing in the future will depend on our financial and operating performance, which, in turn, is subject to then-current economic conditions and to financial, business and other factors. We believe that we will have sufficient cash flow from operations and available borrowings under our Credit Agreement to service our indebtedness. However, a significant downturn in our business or other development adversely affecting our cash flow could materially impair our ability to service our indebtedness. If our cash flow and capital resources are insufficient to fund our debt service obligations, we may be forced to refinance all or a portion of our debt or sell assets. We cannot guarantee that we would be able to refinance our existing indebtedness at maturity or otherwise or sell assets on terms that are commercially reasonable.

The instruments governing our debt contain restrictive covenants that may prevent us from engaging in certain beneficial transactions. The agreements governing our debt generally require us to comply with various affirmative and negative covenants including the maintenance of certain financial ratios and restrictions on incurring additional debt, entering into mergers, consolidations and sales of assets, making investments and granting liens. Additionally, our purchase and contribution agreements with HFC with respect to the intermediate pipelines acquired in 2005 and the crude pipelines and tankage assets acquired in 2008, restrict us from selling these pipelines and terminals acquired from HFC. Under these agreements, we are restricted from prepaying borrowings and long-term debt to outstanding balances below $206 million prior to March 1, 2015 and $171 million prior to March 1, 2018, subject to certain limited exceptions. Our leverage may affect adversely our ability to fund future working capital, capital expenditures and other general partnership requirements, future acquisitions, construction or development activities, or to otherwise realize fully 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. Our leverage also may make our results of operations more susceptible to adverse economic and industry conditions by limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate and may place us at a competitive disadvantage as compared to our competitors that have less debt.

We may not be able to obtain funding on acceptable terms or at all because of volatility and uncertainty in the credit and capital markets. This may hinder or prevent us from meeting our future capital needs.

The domestic and global financial markets and economic conditions are disrupted and volatile from time to time due to a variety of factors, including low consumer confidence, high unemployment, geoeconomic and geopolitical issues, weak economic conditions and uncertainty in the financial services sector. In addition, the fixed-income markets have experienced periods of extreme volatility, which negatively impacted market liquidity conditions. As a result, the cost of raising money in the debt and equity capital markets has increased substantially at times while the availability of funds from these markets diminished significantly. In particular, as a result of concerns about the stability of financial markets generally and the solvency of lending counterparties specifically, the cost of obtaining money from the credit markets may increase as many lenders and institutional investors increase interest rates, enact tighter lending standards, refuse to refinance existing debt on similar terms or at all and reduce, or in some cases cease, to provide funding to borrowers. In addition, lending counterparties under existing revolving credit facilities and other debt instruments may be unwilling or unable to meet their funding obligations.

Due to these factors, we cannot be certain that new debt or equity financing will be available on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to:

- meet our obligations as they come due;

- execute our growth strategy;
- complete future acquisitions or construction projects;
- take advantage of other business opportunities; or
- respond to competitive pressures.

Any of the above could have a material adverse effect on our revenues and results of operations.

We may not be able to fully execute our growth strategy if we encounter illiquid capital markets or increased competition for investment opportunities, if our assumptions concerning population growth are inaccurate, or if an agreement cannot be reached with HFC for the acquisition of assets on which we have a right of first offer.

Our strategy contemplates growth through the development and acquisition of crude, intermediate and refined products transportation and storage assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses, either from HFC or third parties, to enhance our ability to compete effectively and diversifying our asset portfolio, thereby providing more stable cash flow. We regularly consider and enter into discussions regarding, and are currently contemplating and/or pursuing, potential joint ventures, stand-alone projects or other transactions that we believe will present opportunities to realize synergies, expand our role in our chosen businesses and increase our market position.

We will require substantial new capital to finance the future development and acquisition of assets and businesses. Any limitations on our access to capital will impair our ability to execute this strategy. If the cost of such capital becomes too expensive, or if the development or acquisition opportunities are on terms that do not allow us to obtain appropriate financing, our ability to develop or acquire accretive assets will be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence our cost of equity include market conditions, fees we pay to underwriters and other offering costs, which include amounts we pay for legal and accounting services. The primary factors influencing our cost of borrowing include interest rates, credit spreads, covenants, underwriting or loan origination fees and similar charges we pay to lenders.

In addition, we experience competition for the types of assets and businesses we have historically purchased or acquired. High competition, particularly for a limited pool of assets, may result in higher, less attractive asset prices, and therefore, we may lose to more competitive bidders. Such occurrences limit our ability to execute our growth strategy, which may materially adversely affect our ability to maintain or pay higher distributions in the future.

Our growth strategy also depends upon:

- the accuracy of our assumptions about growth in the markets that we currently serve or have plans to serve in the Southwestern, Rocky Mountain and Mid-Continent regions of the United States;
- HFC's willingness and ability to capture a share of additional demand in its existing markets; and
- HFC's willingness and ability to identify and penetrate new markets in the Southwestern, Rocky Mountain and Mid-Continent regions of the United States.

If our assumptions about increased market demand prove incorrect, HFC may not have any incentive to increase refinery capacity and production or shift additional throughput to our pipelines, which would adversely affect our growth strategy.

Our Omnibus Agreement with HFC provides us with a right of first offer on certain of HFC’s existing or acquired logistics assets. The consummation and timing of any future acquisitions of these assets will depend upon, among other things, our ability to negotiate acceptable purchase agreements and commercial agreements with respect to the assets and our ability to obtain financing on acceptable terms. We can offer no assurance that we will be able to successfully consummate any future acquisitions pursuant to our right of first offer. In addition, certain of the assets covered by our right of first offer may require substantial capital expenditures in order to maintain compliance with applicable regulatory requirements or otherwise make them suitable for our commercial needs. For these or a variety of other reasons, we may decide not to exercise our right of first offer if and when any assets are offered for sale, and our decision will not be subject to unitholder approval. In addition, our right of first offer may be terminated upon a change of control of HFC.

We are exposed to the credit risks and certain other risks, of our key customers, vendors, and other counterparties.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers, vendors or other counterparties. We derive a significant portion of our revenues from contracts with key customers, including HFC and Alon under their respective pipelines and terminals, tankage and throughput agreements. To the extent that our customers may be unable to meet the specifications of their customers, we would be adversely affected unless we were able to make comparably profitable arrangements with other customers.

Mergers among our existing customers could provide strong economic incentives for the combined entities to use systems other than ours, and we could experience difficulty in replacing lost volumes and revenues. Because a significant portion of our operating costs are fixed, a reduction in volumes would result not only in a reduction of revenues, but also a decline in net income and cash flow of a similar magnitude, which would reduce our ability to meet our financial obligations and make distributions to unitholders.

If any of our key customers default on their obligations to us, our financial results could be adversely affected. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks. In addition, nonperformance by vendors who have committed to provide us with products or services could result in higher costs or interfere with our ability to successfully conduct our business.

Any substantial increase in the nonpayment and/or nonperformance by our customers or vendors could have a material adverse effect on our results of operations and cash flows.

In addition, in connection with the acquisition of certain of our assets, we have entered into agreements pursuant to which various counterparties, including HFC, have agreed to indemnify us, subject to certain limitations, for:

- certain pre-closing environmental liabilities discovered within specified time periods after the date of the applicable acquisition;
- certain matters arising from the pre-closing ownership and operation of assets; and
- ongoing remediation related to the assets.

Our business, results of operation, cash flows and our ability to make cash distributions to our unitholders could be adversely affected in the future if third parties fail to satisfy an indemnification obligation owed to us.

Competition from other pipelines that may be able to supply our shippers' customers with refined products at a lower price could cause us to reduce our rates or could reduce our revenues.

We and our shippers could face increased competition if other pipelines are able to supply our shippers' end-user markets competitively with refined products. For example, increased supplies of refined product delivered by Kinder Morgan's El Paso to Phoenix pipeline could result in additional downward pressure on wholesale-refined product prices and refined product margins in El Paso and related markets. Additionally, further increases in products from Gulf Coast refiners entering the El Paso and Arizona markets on this pipeline and a resulting increase in the demand for shipping product on the interconnecting common carrier pipelines could cause a decline in the demand for refined product from HFC and/or Alon. This could reduce our opportunity to earn revenues from HFC and Alon in excess of their minimum volume commitment obligations.

An additional factor that could affect some of HFC's and Alon's markets is excess pipeline capacity from the West Coast into our shippers' Arizona markets. Additional increases in shipments of refined products from the West Coast into our shippers' Arizona markets could result in additional downward pressure on refined product prices that, if sustained over the long term, could influence product shipments by HFC and Alon to these markets.

A material decrease in the supply, or a material increase in the price, of crude oil available to HFC's and Alon's refineries, and a corresponding decrease in demand for refined products in the markets served by our pipelines and terminals, could reduce our revenues materially.

The volume of refined products we transport in our refined product pipelines depends on the level of production of refined products from HFC's and Alon's refineries, which, in turn, depends on the availability of attractively-priced crude oil produced in the areas accessible to those refineries. In order to maintain or increase production levels at their refineries, our shippers must continually contract for new crude oil supplies. A material decrease in crude oil production from the fields that supply their refineries, as a result of depressed commodity prices, decreased demand, lack of drilling activity, natural production declines or otherwise, could result in a decline in the volume of crude oil our shippers refine, absent the availability of transported crude oil to offset such declines. Such an event would result in an overall decline in volumes of refined products transported through our pipelines and therefore a corresponding reduction in our cash flow. In addition, the future growth of our shippers' operations will depend in part upon whether our shippers can contract for additional supplies of crude oil at a greater rate than the rate of natural decline in their currently connected supplies.

Fluctuations in crude oil prices can greatly affect production rates and investments by third parties in the development of new oil reserves. Drilling activity generally decreases as crude oil prices decrease. We and our shippers have no control over producers or their production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, geological considerations, governmental regulation and the availability and cost of capital, or over the level of drilling activity in the areas of operations, the amount of reserves underlying the wells and the rate at which production from a well will decline. Similarly, a material increase in the price of crude oil supplied to our shippers' refineries without an increase in the market value of the products produced by the refineries, either temporary or permanent, which causes a reduction in the production of refined products at the refineries, would cause a reduction in the volumes of refined products we transport, and our cash flow could be adversely affected.

Finally, our business depends in large part on the demand for the various petroleum products we gather, transport and store in the markets we serve. Reductions in that demand adversely affect our business. Market demand varies based upon the different end uses of the petroleum products we gather, transport and store. We cannot predict the impact of future fuel conservation measures, alternate fuel requirements, government regulation, technological advances in fuel economy and energy-generation devices, exploration and production activities, and actions by foreign nations, any of which could reduce the demand for the petroleum products in the areas we serve.

We may not be able to retain existing customers or acquire new customers.

The renewal or replacement of existing contracts with our customers at rates sufficient to maintain attractive revenues and cash flows depends on a number of factors outside our control, including competition from other pipelines and the demand for refined products in the markets that we serve. Our long-term pipeline and terminal, tankage and throughput agreements with HFC and Alon expire beginning in 2019 through 2026.

Our operations are subject to evolving federal, state and local environmental, health and safety laws and regulations, and potential liabilities that could affect our operations and adversely affect our performance.

Environmental laws and regulations have raised operating costs for the oil and refined products industry, and compliance with such laws and regulations may cause us, and the HFC and Alon refineries that we support, to incur potentially material capital expenditures associated with the construction, maintenance, and upgrading of equipment and facilities. We may also be required to address conditions discovered in the future that require environmental response actions or remediation. Future environmental, health and safety requirements (or changed interpretations of existing requirements) may impose more stringent requirements on our assets and operations and require us to incur potentially material expenditures to ensure our continued compliance.

Currently, various legislative and regulatory measures to address greenhouse gas emissions (including carbon dioxide, methane and other gases) are in various phases of discussion or implementation. These include requirements that HFC's and Alon's refineries report emissions of greenhouse gases to the EPA, and proposed federal, state, and regional initiatives that require (or could require) us, HFC and Alon to reduce greenhouse gas emissions from our facilities. Requiring reductions in greenhouse gas emissions could cause us to incur substantial costs to (i) operate and maintain our facilities, (ii) install new emission controls at our facilities and (iii) administer and manage any greenhouse gas emissions programs, including the acquisition or maintenance of emission credits or allowances. These requirements may affect HFC's and Alon's refinery operations and have an indirect adverse effect on our business, financial condition and results of our operations.

Requiring a reduction in greenhouse gas emissions and the increased use of renewable fuels could also decrease demand for refined products, which could have an indirect, but material, adverse effect on our business, financial condition and results of operations. For example, in 2010, the EPA promulgated a rule establishing greenhouse gas emission standards for new-model passenger cars, light-duty trucks, and medium-duty passenger vehicles. Also in 2010, the EPA promulgated a rule establishing greenhouse gas emission thresholds for the permitting of certain stationary sources, which could require greenhouse emission controls for those sources. Discussions are underway for proposed additional regulations in both of these areas. For example, consistent with its Climate Action Plan announced in 2014, the Obama Administration is expected to release a series of new regulations affecting the oil and gas industry in 2015, including regulations limiting methane emissions from certain new and modified oil and gas facilities. These requirements could have an indirect adverse effect on our business due to reduced demand for crude oil and refined products, and a direct adverse effect on our business from increased regulation of our facilities.

We may incur significant costs and liabilities resulting from performance of pipeline integrity programs and related repairs.
PHMSA has promulgated regulations requiring pipeline operators to develop and implement integrity management programs for certain pipelines that, in the event of a pipeline leak or rupture could affect “high consequence areas,” which are areas where a release could have the most significant adverse consequences, including high-population areas, certain drinking water sources and unusually sensitive ecological areas. These regulations require operators of covered pipelines to perform a variety of heightened inspection, analysis, prevention and repair activities. A number of states have adopted regulations similar to existing PHMSA regulations for certain pipelines.

Moreover, changes to pipeline safety laws by Congress and regulations by PHMSA or states that result in more stringent or costly safety standards could possibly have a substantial effect on us and similarly situated midstream operators.

Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more stringent enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation.
Among other things, the 2011 Amendments to the Pipeline Safety Act direct the Secretary of Transportation to study, and where appropriate based on the results and statutory factors, promulgate regulations relating to expanded integrity management requirements, automatic or remote-controlled valves, leak detection, and other requirements. The 2011 Amendments also increased the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day and also from $1 million to $2 million for a related series of violations. The safety enhancement requirements and other provisions of the 2011 Amendments as well as any implementation of PHMSA regulations thereunder, reinterpretation of existing laws or regulations, or any issuance or reinterpretation of guidance by PHMSA or any state agencies with respect to the 2011 Amendments could require us to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could have a material adverse effect on our results of operations or financial position. For example, PHMSA is expected to issue new and expanded proposed regulations in 2015 applicable to pipeline operators, including provisions that may expand to the integrity management requirements to additional pipeline mileage. Such new and expanded requirements may result in additional capital costs, possible operational delays and increased costs of operation that, in some instances, may be significant.

Increases in interest rates could adversely affect our business.

We use both fixed and variable rate debt, and we are exposed to market risk due to the floating interest rates on our credit facility. From time to time we use interest rate derivatives to hedge interest obligations on specific debt. In addition, interest rates on future debt offerings could be higher, causing our financing costs to increase accordingly. Our results of operations, cash flows and financial position could be adversely affected by significant increases in interest rates above current levels.

We may be subject to information technology system failures, network disruptions and breaches in data security.

Information technology system failures, network disruptions (whether intentional by a third party or due to natural disaster), breaches of network or data security, or disruption or failure of the network system used to monitor and control pipeline operations could disrupt our operations by impeding our processing of transactions, our ability to protect customer or company information and our financial reporting. Our computer systems, including our back-up systems, could be damaged or interrupted by power outages, computer and telecommunications failures, computer viruses, internal or external security breaches, events such as fires, earthquakes, floods, tornadoes and hurricanes, and/or errors by our employees. Although we have taken steps to address these concerns by implementing sophisticated network security and internal control measures, a system failure or data security breach could have a material adverse effect on our financial condition and results of operations.

Our operations are subject to federal, state, and local laws and regulations, and permit and authorization requirements, relating to product quality specifications, environmental protection and operational safety that could require us to make substantial expenditures.

Our pipelines and terminals, tankage and loading rack operations are subject to increasingly strict environmental and safety laws and regulations. Also, the transportation and storage of refined products produces a risk that refined products and other hydrocarbons may be suddenly or gradually released into the environment, potentially causing substantial expenditures for a response action, significant government penalties, liability to government agencies for natural resources damages, personal injury or property damages to private parties and significant business interruption. We own or lease a number of properties that have been used to store or distribute refined products for many years. Many of these properties also have been operated by third parties whose handling, disposal, or release of hydrocarbons and other wastes were not under our control. If we were to incur a significant liability pursuant to environmental laws or regulations, it could have a material adverse effect on us. Also we are subject to the requirements of the Federal Occupational Safety and Health Administration ("OSHA"), and comparable state statutes. Any violation of OSHA could impose substantial costs on us.

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

Our operations require numerous permits and authorizations under various laws and regulations, including environmental and health and safety laws and regulations. These authorizations and permits are subject to revocation, renewal or modification and can require operational changes that may involve significant costs to limit impacts or potential impacts on the environment and/or health and safety. A violation of these authorization or permit conditions or other legal or regulatory requirements could result in substantial fines, criminal sanctions, permit revocations and injunctions prohibiting our operations. In addition, major modifications of our operations could require modifications to our existing permits or expensive upgrades to our existing pollution control equipment that could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our operations are subject to operational hazards and unforeseen interruptions for which we may not be adequately insured.

Our operations are subject to operational hazards and unforeseen interruptions such as natural disasters, adverse weather, accidents, fires, explosions, hazardous materials releases, mechanical failures and other events beyond our control. These events might result in a loss of life, loss of equipment or destruction of property, injury, or extensive property damage, as well as a curtailment or interruption in our operations. In addition, third-party damage, mechanical malfunctions, undetected leaks in pipelines, faulty measurement or other errors may result in significant costs or lost revenues.

We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates and exclusions from coverage may limit our ability to recover the amount of the full loss in all situations. As a result of market conditions, premiums and deductibles for certain of our insurance policies could increase. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position. Because of our distribution policy, we do not have the same flexibility as other legal entities to accumulate cash to protect against underinsured or uninsured losses.

There can be no assurance that insurance will cover all damages and losses resulting from these types of hazards. We are not fully insured against all risks incident to our business. We are not insured against all environmental accidents that might occur, other than some coverage for third party sudden and accidental claims. Our property insurance includes business interruption coverage for lost profit arising from physical damage to our facilities. If a significant accident or event occurs that is not fully insured, our operations could be temporarily or permanently impaired, and our liabilities and expenses could be significant.

Any reduction in the capacity of, or the allocations to, our shippers on interconnecting, third-party pipelines could cause a reduction of volumes transported in our pipelines and through our terminals.

HFC, Alon and the other users of our pipelines and terminals are dependent upon connections to third-party pipelines to receive and deliver crude oil and refined products. Any reduction of capacities of these interconnecting pipelines due to testing, line repair, reduced operating pressures, or other causes could result in reduced volumes transported in our pipelines or through our terminals. Similarly, if additional shippers begin transporting volumes of refined products over interconnecting pipelines, the allocations to existing shippers in these pipelines would be reduced, which could also reduce volumes transported in our pipelines or through our terminals.

We could be subject to damages based on claims brought against us by our customers or lose customers as a result of the failure of products we distribute to meet certain quality specifications.

A significant portion of our operating responsibility on refined product pipelines is to ensure the quality and purity of the products loaded at our loading racks. If our quality control measures fail, off-specification product could be sent out to public gasoline stations. This type of incident could result in liability claims regarding damages caused by the off-specification fuel or could impact our ability to retain existing customers or to acquire new customers, any of which could have a material adverse impact on our results of operations and cash flows.

Growing our business by constructing new pipelines and terminals, or expanding existing ones, subjects us to construction risks.

One of the ways we may grow our business is through the construction of new pipelines and terminals or the expansion of existing ones. The construction of a new pipeline or the expansion of an existing pipeline, by adding horsepower or pump stations or by adding a second pipeline along an existing pipeline, involves numerous regulatory, environmental, political, and legal uncertainties, most of which are beyond our control. These projects may not be completed on schedule (or at all) or at the budgeted cost. In addition, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we build a new pipeline, the construction will occur over an extended period of time and we will not receive any material increases in revenues until after completion of the project. Moreover, we may construct facilities to capture anticipated future growth in demand for refined products in a region in which such growth does not materialize. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition.

Rate regulation, changes to rate-making rules, or a successful challenge to the rates we charge may reduce our revenues and the amount of cash we generate.

The FERC regulates the tariff rates for interstate movements and state regulatory authorities regulate the tariff rates for intrastate movements on our pipeline systems. The regulatory agencies that regulate our systems periodically implement new rules, regulations and terms and conditions of services subject to their jurisdiction. New initiatives or orders may adversely affect the rates charged for our services.

The primary rate-making methodology of the FERC is price indexing. We use this methodology in all of our interstate markets. The indexing method allows a pipeline to increase its rates based on a percentage change in the producer price index for finished goods. If the index falls, we will be required to reduce our rates that are based on the FERC's price indexing methodology if they exceed the new maximum allowable rate. If the FERC price indexing methodology permits a rate increase that is not large enough to fully reflect actual increases in our costs, we may need to file for a rate increase using an alternative method with a much higher burden of proof and without the guarantee of success. These FERC rate-making methodologies may limit our ability to set rates based on our true costs or may delay the use of rates that reflect increased costs. Any of the foregoing would adversely affect our revenues and cash flow.

If a party with an economic interest were to file either a protest of our proposal for increased rates or a complaint against our existing tariff rates, or the FERC were to initiate an investigation of our existing rates, then our rates could be subject to detailed review. If our proposed rate increases were found to be in excess of levels justified by our cost of service, the FERC could order us to reduce our rates, and to refund the amount by which the rate increases were determined to be excessive, plus interest. If our existing rates were found to be in excess of our cost of services, we could be ordered to refund the excess we collected for up to two years prior to the date of the filing of the complaint challenging the rates, and we could be ordered to reduce our rates prospectively. In addition, a state commission also could investigate our intrastate rates or our terms and conditions of service on its own initiative or at the urging of a shipper or other interested party. If a state commission found that our rates exceeded levels justified by our cost of service, the state commission could order us to reduce our rates. Any such reductions may result in lower revenues and cash flows if additional volumes and/or capacity are unavailable to offset such rate reductions.

HFC and Alon have agreed not to challenge, or to cause others to challenge or assist others in challenging, our tariff rates in effect during the terms of their respective pipelines and terminals agreements; however, other current or future shippers may still challenge our tariff rates.

Terrorist attacks, and the threat of terrorist attacks or domestic vandalism, have resulted in increased costs to our business. Continued global hostilities or other sustained military campaigns may adversely impact our results of operations.

The long-term impact of terrorist attacks, such as the attacks that occurred on September 11, 2001, and the threat of future terrorist attacks, on the energy transportation industry in general, and on us in particular, is unknown. Increased security measures taken by us as a precaution against possible terrorist attacks or vandalism have resulted in increased costs to our business. Uncertainty surrounding continued global hostilities or other sustained military campaigns, and the possibility that infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror, may affect our operations in unpredictable ways, including disruptions of crude oil supplies and markets for refined products.

Changes in the insurance markets attributable to terrorist attacks could make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital including our ability to repay or refinance debt.

Adverse changes in our and/or our general partner's credit ratings and risk profile may negatively affect us.

Our ability to access capital markets is important to our ability to operate our business. Regional and national economic conditions, increased scrutiny of the energy industry and regulatory changes, as well as changes in our economic performance, could result in credit agencies reexamining our credit rating. While credit ratings reflect the opinions of the credit agencies issuing such ratings and may not necessarily reflect actual performance, a downgrade in our credit rating could restrict or discontinue our ability to access capital markets at attractive rates, could result in an increase in our borrowing costs and a reduction in our level of capital expenditures and could impact our future earnings and cash flows.

We are in compliance with all covenants or other requirements set forth in our Credit Agreement. Further, we do not have any rating downgrade triggers that would automatically accelerate the maturity dates of any debt. However, a downgrade in our credit rating could affect adversely our ability to borrow on, renew existing, or obtain access to new financing arrangements and would increase the cost of such financing arrangements.

The credit and business risk profiles of our general partner, and of HFC as the indirect owner of our general partner, may be factors in credit evaluations of us as a master limited partnership due to the significant influence of our general partner and its indirect owner over our business activities, including our cash distribution acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of our general partner and its owners, including the degree of their financial leverage and their dependence on cash flow from the partnership to service their indebtedness.

We may be unsuccessful in integrating the operations of the assets we have acquired or may acquire with our operations, and in realizing all or any part of the anticipated benefits of any such acquisitions.

From time to time, we evaluate and acquire assets and businesses that we believe complement our existing assets and businesses. Acquisitions may require substantial capital or the incurrence of substantial indebtedness. Our capitalization and results of operations may change significantly as a result of completed or future acquisitions. Acquisitions and business expansions involve numerous risks, including difficulties in the assimilation of the assets and operations of the acquired businesses, inefficiencies and difficulties that arise because of unfamiliarity with new assets and the businesses associated with them, and new geographic areas and the diversion of management's attention from other business concerns. Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. Also, following an acquisition, we may discover previously unknown liabilities associated with the acquired business or assets for which we have no recourse under applicable indemnification provisions.

If we are unable to complete capital projects at their expected costs or in a timely manner, or if the market conditions assumed in our project economics deteriorate, our financial condition, results of operations, or cash flows could be materially and adversely affected.

Delays or cost increases related to capital spending programs involving construction of new facilities (or improvements and repairs to our existing facilities) could adversely affect our ability to achieve forecasted operating results. Although we evaluate and monitor each capital spending project and try to anticipate difficulties that may arise, such delays or cost increases may arise as a result of numerous factors, such as:

- denial or delay in issuing requisite regulatory approvals and/or permits;

- unplanned increases in the cost of construction materials or labor;
- disruptions in transportation of modular components and/or construction materials;
- severe adverse weather conditions, natural disasters, or other events (such as equipment malfunctions explosions, fires or spills) affecting our facilities, or those of vendors and suppliers;
- shortages of sufficiently skilled labor, or labor disagreements resulting in unplanned work stoppages;
- market-related increases in a project's debt or equity financing costs; and/or
- nonperformance by, or disputes with, vendors, suppliers, contractors, or sub-contractors involved with a project.

If we are unable to complete capital projects at their expected costs or in a timely manner our financial condition, results of operations, or cash flows could be materially and adversely affected.

We do not own all of the land on which our pipeline systems and other assets are located, which could result in disruptions to our operations.

We do not own all of the land on which our pipeline systems and other assets are located, and we are, therefore, subject to the risk of increased costs or more burdensome terms to maintain necessary land use. We obtain the right to construct and operate pipelines and other assets on land owned by third parties and government agencies for specified periods. If we were to lose these rights through an inability to renew leases, right-of-way contracts or similar agreements, we may be required to relocate our pipelines or other assets and our business could be adversely affected. Additionally, it may become more expensive for us to obtain new rights-of-ways or leases or to renew existing rights-of-ways or leases. If the cost of obtaining or renewing such agreements increases, it may adversely affect our operations and the cash flows available for distribution to unitholders.

Our business may suffer due to a change in the composition of our Board of Directors, if any of our key senior executives or other key employees who provide services to us discontinue employment, or if certain of our executive officers, who also allocate time to our general partner and its affiliates, do not have enough time to dedicate to our business. Furthermore, a shortage of skilled labor or disruptions in the labor force that provides services to us may make it difficult for us to maintain labor productivity.

Our future success depends to a large extent on the services of HLS's Board of Directors, key senior executives and key senior employees who provide services to us. Also, our business depends on the continuing ability to recruit, train and retain highly qualified employees in all areas of our operations, including accounting, business operations, finance and other key back-office and mid-office personnel. The competition for these employees is intense, and the loss of these executives or employees could harm our business. If any of these executives or other key personnel resign or become unable to continue in their present roles and are not adequately replaced, our business operations could be materially adversely affected. We do not maintain any “key man” life insurance for any executives. Furthermore, our operations require skilled and experienced laborers with proficiency in multiple tasks.

Our general partner shares officers and administrative personnel with HFC to operate both our business and HFC's business. These officers face conflicts regarding the allocation of their and other employees' time, which may affect adversely our results of operations, cash flows and financial condition.

As of December 31, 2014, approximately 15% of HFC's employees dedicated to providing services for us were represented by labor unions under collective bargaining agreements with various expiration dates. HFC may not be able to renegotiate the collective bargaining agreements when they expire on satisfactory terms or at all. A failure to do so may increase our costs. In addition, existing labor agreements may not prevent a future strike or work stoppage, and any work stoppage could negatively affect our results of operations and financial condition.

RISKS TO COMMON UNITHOLDERS

HFC and its affiliates may have conflicts of interest and limited fiduciary duties, which may permit them to favor their own interests.

Currently, HFC indirectly owns the 2% general partner interest and a 37% limited partner interest in us and owns and controls HLS, the general partner of our general partner, HEP Logistics Holdings, L.P. (“HEP Logistics”). Conflicts of interest may arise between HFC and its affiliates, including our general partner, on the one hand, and us, on the other hand. As a result of these conflicts, the general partner may favor its own interests and the interests of its other affiliates over our interests. These conflicts include, among others, the following situations:

- HFC, as a shipper on our pipelines, has an economic incentive not to cause us to seek higher tariff rates or terminalling fees, even if such higher rates or terminalling fees would reflect rates that could be obtained in arm's-length, third-party transactions;
- neither our partnership agreement nor any other agreement requires HFC to pursue a business strategy that favors us or utilizes our assets, including whether to increase or decrease refinery production, whether to shut down or reconfigure a refinery, or what markets to pursue or grow. HFC's directors and officers have a fiduciary duty to make these decisions in the best interests of the stockholders of HFC;
- our general partner is allowed to take into account the interests of parties other than us, such as HFC, in resolving conflicts of interest;

- our partnership agreement provides for modified or reduced fiduciary duties for our general partner, and also restricts the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- our general partner determines which costs incurred by HFC and its affiliates are reimbursable by us;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our general partner may, in some circumstances, cause us to borrow funds to make cash distributions, even where the purpose or effect of the borrowing benefits our general partner or affiliates;
- our general partner determines the amount and timing of our asset purchases and sales, capital expenditures and borrowings, each of which can affect the amount of cash available to us; and
- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates, including the pipelines and terminals agreement with HFC.

Cost reimbursements, which will be determined by our general partner, and fees due to our general partner and its affiliates for services provided, are substantial.

Under our Omnibus Agreement, we are obligated to pay HFC an administrative fee ($2.3 million in 2014 and currently $2.4 million) per year for the provision by HFC or its affiliates of various general and administrative services for our benefit. In addition, we are required to reimburse HFC pursuant to the secondment arrangement for the wages, benefits, and other costs of HFC employees seconded to HLS to perform services at certain of our pipelines and tankage assets. We can neither provide assurance that HFC will continue to provide us the officers and employees that are necessary for the conduct of our business nor that such provision will be on terms that are acceptable to us. If HFC fails to provide us with adequate personnel, our operations could be adversely impacted.

The administrative fee is subject to annual review and may increase if we make an acquisition that requires an increase in the level of general and administrative services that we receive from HFC or its affiliates. Our general partner will determine the amount of general and administrative expenses that will be allocated to us in accordance with the terms of our partnership agreement. In addition, our general partner and its affiliates are entitled to reimbursement for all other expenses they incur on our behalf, including the salaries of and the cost of employee benefits for employees of HLS who provide services to us.

Prior to making any distribution on the common units, we will reimburse our general partner and its affiliates, including officers and directors of the general partner, for all expenses incurred on our behalf, plus the administrative fee. The reimbursement of expenses and the payment of fees could adversely affect our ability to make distributions. The general partner has sole discretion to determine the amount of these expenses. Our general partner and its affiliates also may provide us other services for which we are charged fees as determined by our general partner.

Increases in interest rates could adversely impact our unit price and our ability to issue additional equity to make acquisitions, fund expansion capital expenditures, or for other purposes.

As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity to make acquisitions, fund expansion capital expenditures or for other purposes. If we then issue additional equity at a significantly lower price, material dilution to our existing unitholders could result.

Even if unitholders are dissatisfied, they cannot remove our general partner without its consent.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders did not elect our general partner or the board of directors of HLS and have no right to do so on an annual or other continuing basis. The board of directors of HLS is chosen by the sole member of HLS. If unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. As a result of these limitations, the price at which the common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

The vote of the holders of at least 66 2/3% of all outstanding units voting together as a single class is required to remove the general partner. Unitholders will be unable to remove the general partner without its consent because the general partner and its affiliates own sufficient units to prevent its removal. Unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding (other than the general partner, its affiliates, their transferees, and persons who acquired such units with the prior approval of the board of directors of the general partner's general partner) cannot vote on any matter; however, no such person currently exists. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings, acquire information about our operations, and influence the manner or direction of management.

The control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of the partners of our general partner from transferring their respective partnership interests in our general partner to a third party. The new partners of our general partner would then be in a position to replace the board of directors and officers of the general partner of our general partner with their own choices and to control the decisions made by the board of directors and officers.

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

Under our partnership agreement, provided there is no significant decrease in our operating performance, we may issue an unlimited number of limited partner interests of any type without the approval of our unitholders, and HEP currently has a shelf registration on file with the SEC pursuant to which it may issue up to $2.0 billion in additional common units.

The issuance by us 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 the common units may decline.

Our partnership agreement does not give our unitholders the right to approve our issuance of equity securities ranking junior to the common units at any time.

In establishing cash reserves, our general partner may reduce the amount of cash available for distribution to unitholders.

Our partnership agreement requires our general partner to deduct from operating surplus cash reserves that it establishes are necessary to fund our future operating expenditures. In addition, our partnership agreement permits our general partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party, or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash available to make the required payments to our debt holders or to pay the minimum quarterly distribution on our common units every quarter.

HFC and its affiliates may engage in limited competition with us.

HFC and its affiliates may engage in limited competition with us. Pursuant to the Omnibus Agreement, HFC and its affiliates agreed not to engage in the business of operating intermediate or refined product pipelines or terminals, crude oil pipelines or terminals, truck racks or crude oil gathering systems in the continental United States. The Omnibus Agreement, however, does not apply to:

- any business operated by HFC or any of its subsidiaries at the closing of our initial public offering;
- any business or asset that HFC or any of its subsidiaries acquires or constructs that has a fair market value or construction cost of less than $5 million; and
- any business or asset that HFC or any of its subsidiaries acquires or constructs that has a fair market value or construction cost of $5 million or more if we have been offered the opportunity to purchase the business or asset at fair market value, and we decline to do so.

In the event that HFC or its affiliates no longer control our partnership or there is a change of control of HFC, the non-competition provisions of the Omnibus Agreement will terminate.

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

If at any time our general partner and its affiliates own more than 80% of the common units (which it does not presently), our general partner will have the right (which it may assign to any of its affiliates or to us) but not the obligation to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, a holder of common units may be required to sell its units at a time or price that is undesirable to it and may not receive any return on its investment. A common unitholder may also incur a tax liability upon a sale of its units.

A unitholder may not have limited liability if a court finds that unitholder actions constitute control of our business or that we have not complied with state partnership law.

Under Delaware law, a unitholder could be held liable for our obligations to the same extent as a general partner if a court determined that the right of unitholders to remove our general partner or to take other action under our partnership agreement constituted participation in the “control” of our business. Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those contractual obligations that are expressly made without recourse to our general partner.

In addition, Section 17-607 and 17-804 of the Delaware Revised Uniform Limited Partnership Act provides that under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

Further, we conduct business in a number of states. In some of those states the limitations on the liability of limited partners for the obligations of a limited partnership have not been clearly established. The unitholders might be held liable for the partnership's obligations as if they were a general partner if a court or government agency determined that we were conducting business in the state but had not complied with the state's partnership statute.

HFC may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.

HFC currently holds 22,380,030 of our common units, which is approximately 37% of our outstanding common units. Additionally, we agreed to provide HFC registration rights with respect to our common units that it holds. The sale of these units in the public or private markets could have an adverse impact on the trading price of our common units.

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. If the U.S. Internal Revenue Service (the “IRS”) were to treat us as a corporation for federal income tax purposes or if we were to become subject to additional amounts of entity-level taxation for federal or state tax purposes, 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.

Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes unless we satisfy a "qualifying income" requirement and are not treated as an investment company. Based upon our current operations, we believe we satisfy the qualifying income requirement and are not treated as an investment company. Failing to meet the qualifying income requirement, being treated as an investment company, 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 likely pay state income tax at varying rates. Distributions to unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to unitholders. 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 unitholders, likely causing a substantial reduction in the value of our common units.

At the entity level, were we to be subject to federal income tax, we would also be subject to the income tax provisions of many states. Moreover, because of widespread state budget deficits and other reasons, several states are evaluating ways to independently subject partnerships to entity-level taxation through the imposition of state income taxes, franchise taxes and other forms of taxation. For example, we are required to pay Texas margin tax on any income apportioned to Texas. Imposition of any additional such taxes on us or an increase in the existing tax rates would reduce the cash available for distributions to our unitholders.

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

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, from time to time, the administration or members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. One such legislative proposal would eliminate the qualifying income exception upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible to meet the qualifying income requirement to be treated as a partnership for U.S. federal income tax purposes.

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

The IRS may adopt positions that differ from the positions we have taken or may take on tax matters. 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, the costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

Even if you do not receive any cash distributions from us, you will be required to pay taxes on your share of our taxable income.

You will be required to pay federal income taxes and, in some cases, state and local income taxes, on your share of our taxable income, whether or not you receive cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax due from you with respect to that income.

Tax gain or loss on the disposition of our common units could be more or less than expected.
If a unitholder disposes of common units, it will recognize gain or loss equal to the difference between the amount realized and its tax basis in those common units. Because distributions in excess of a unitholder's allocable share of our net taxable income result in a decrease of the unitholder's tax basis in its common units, the amount, if any, of such prior excess distributions with respect to the units sold will, in effect, become taxable income to the unitholder if it sells such units at a price greater than its tax basis in those units, even if the price the unitholder receives is less than its original cost. Moreover, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture of items including depreciation recapture. In addition, because the

amount realized includes a unitholder's share of our nonrecourse 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.

An investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts ("IRAs"), Keogh Plans and 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 each non-U.S. person will be required to file U.S. federal tax returns and pay tax on their share of our taxable income. Tax-exempt entities and non-U.S. persons should consult their tax adviser before investing in our common units.

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

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

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

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing treasury regulations, and although the Department of the Treasury issued proposed treasury regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items, the proposed regulations are not final and do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are the subject of a securities loan (e.g., a loan to a “short seller” to cover a short sale of units) may be considered as having disposed of those units. If so, it 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 there are no specific rules governing the federal income tax consequences of loaning a partnership interest, a unitholder whose units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, 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, 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.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the

Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

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

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 are sales or exchanges which, in the aggregate, constitute 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. 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 our unitholders may receive two Schedules K-1) for one fiscal year and may result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in its 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 for federal tax purposes, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the tax years in which the termination occurs.

Unitholders likely will be subject to state and local taxes and return filing requirements as a result of investing in our common units.

In addition to federal income taxes, unitholders likely will be subject to other taxes, such as state and local income 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 now or in the future. Unitholders likely will be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions, even if they do not live in these jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. We currently own property and conduct business in Texas, New Mexico, Arizona, Utah, Idaho, Oklahoma, Washington, Kansas, Wyoming and Nevada. We may own property or conduct business in other states or foreign countries in the future. It is the unitholder's responsibility to file all federal, state, local and foreign tax returns.

Item 1B. Unresolved Staff Comments

We do not have any unresolved SEC staff comments.

Item 2. Properties

PIPELINES

Our refined product pipelines transport light refined products from HFC’s Navajo refinery in New Mexico and Alon’s Big Spring refinery in Texas to their customers in the metropolitan and rural areas of Texas, New Mexico, Arizona, Utah, Oklahoma and northern Mexico and from various refineries in Utah, Wyoming, and Montana (including HFC's Woods Cross refinery in Utah) to Las Vegas, Nevada and Cedar City, Utah. The refined products transported in these pipelines include conventional gasolines, federal, state and local specification reformulated gasoline, low-octane gasoline for oxygenate blending, distillates that include high- and low-sulfur diesel and jet fuel and LPGs (such as propane, butane and isobutane).

Our intermediate product pipelines consist principally of three parallel pipelines that originate at the Navajo refinery Lovington facilities and terminate at its Artesia facilities. These pipelines transport intermediate feedstocks and crude oil for HFC’s refining operations in New Mexico.

Our crude pipelines consist of crude oil trunk, gathering and connection pipelines located in West Texas, New Mexico and Oklahoma that deliver crude oil to the Navajo refinery and crude oil and refined product pipelines that support HFC’s Woods Cross refinery.

Our pipelines are regularly inspected, are well maintained and, we believe, are in good repair. Generally, other than as may be provided in certain pipelines and terminal agreements, substantially all of our pipelines are unrestricted as to the direction in which product flows and the types of refined products that we can transport on them. The FERC regulates the transportation tariffs for interstate shipments on our refined product pipelines and state regulatory agencies regulate the transportation tariffs for intrastate shipments on our pipelines.

The following table details the average aggregate daily number of barrels of petroleum products transported on our pipelines in each of the periods set forth below for HFC and for third parties.

	Years Ended December 31,				
	2014	2013	2012	2011	2010
Volumes transported for (bpd):					
HFC	457,014	397,359	405,718	345,990	324,382
Third parties	64,055	63,337	63,152	52,361	38,910
Total	521,069	460,696	468,870	398,351	363,292
Total barrels in thousands ("mbbls")	190,190	168,154	171,606	145,398	132,602

The following table sets forth certain operating data for each of our refined product, intermediate and crude pipelines. Throughput is the total average number of barrels per day transported on a pipeline but does not aggregate barrels moved between different points on the same pipeline. Revenues reflect tariff revenues generated by barrels shipped from an origin to a delivery point on a pipeline. Revenues also include payments made by Alon under capacity lease arrangements on our Orla to El Paso pipeline. Under these arrangements, we provide space on our pipeline for the shipment of up to 15,000 barrels of refined product per day. Alon pays us whether or not it actually ships the full volumes of refined products it is entitled to ship. To the extent Alon does not use its capacity; we are entitled to use it. We calculate the capacity of our pipelines based on the throughput capacity for barrels of gasoline equivalent that may be transported in the existing configuration; in some cases, this includes the use of drag reducing agents.

Origin and Destination	Diameter (inches)	Length (miles)	Capacity (bpd)	
Refined Product Pipelines:				
Artesia, NM to El Paso, TX	6	156	19,000	
Artesia, NM to Orla, TX to El Paso, TX	8/12/8	214	70,000	(1)
Artesia, NM to Moriarty, NM(2)	12/8	215	27,000	(3)
Moriarty, NM to Bloomfield, NM(2)	8	191	14,400	(3)
Big Spring, TX to Abilene, TX	6/8	100	20,000	
Big Spring, TX to Wichita Falls, TX	6/8	227	23,000	
Wichita Falls, TX to Duncan, OK	6	47	21,000	
Midland, TX to Orla, TX	8/10	135	25,000	
Artesia, NM to Roswell, NM	4	35	5,300	
Woods Cross, UT	10/12/8	8	70,000	
Woods Cross, UT to Las Vegas, NV	12	427	62,000	
Tulsa, OK(4)				
Intermediate Product Pipelines:				
Lovington, NM to Artesia, NM	8	65	48,000	
Lovington, NM to Artesia, NM	10	65	72,000	
Lovington, NM to Artesia, NM	16	65	98,400	
Tulsa, OK(5)	8/10/12	7		(5)
Crude Pipelines:				
Artesia Region Gathering	Various	497	60,000	
West Texas Gathering	Various	305	35,000	
Roadrunner Pipeline	16	69	62,400	
Beeson Pipeline	8	41	50,400	

(1) Includes 15,000 bpd of capacity on the Orla to El Paso segment of this pipeline that is leased to Alon under capacity lease agreements.

(2) The White Lakes Junction to Moriarty segment of our Artesia to Moriarty pipeline and the Moriarty to Bloomfield pipeline is leased from Mid-America Pipeline Company, LLC ("Mid-America") under a long-term lease agreement.

(3) Capacity for this pipeline is reflected in the information for the Artesia to Moriarty pipeline.

(4) Tulsa gasoline and diesel fuel connections to Magellan's pipeline of less than one mile.

(5) The capacities of the three gas pipelines are 10 million standard cubic feet per day (“MMSCFD”), 22 MMSCFD, and 10 MMSCFD and the two liquid pipelines are 45,000 BPD and 60,000 BPD.

HFC shipped an aggregate of 65.0% of the petroleum products transported on our refined product pipelines and 98.0% of the petroleum products transported on our intermediate pipelines and crude oil pipelines in 2014. These pipelines transported 81.1% of the light refined products produced by HFC's Navajo refinery in 2014.

Artesia, New Mexico to El Paso, Texas

The Artesia to El Paso refined product pipeline is regulated by the FERC. It was constructed in 1959 and consists of 156 miles of 6-inch pipeline. This pipeline is used primarily for the shipment of refined products produced at the Navajo refinery to our El Paso terminal, where we deliver to common carrier pipelines for transportation to Arizona, northern New Mexico, northern Mexico and to the terminal's tank farm for truck rack loading for local delivery by tanker truck. Refined products produced at the Navajo refinery destined for El Paso are transported on either this pipeline or our Artesia to Orla to El Paso pipeline.

Artesia, New Mexico to Orla, Texas to El Paso, Texas

The Artesia to Orla to El Paso refined product pipeline is a common-carrier pipeline regulated by the FERC and consists of three segments:

- an 8-inch and a 12-inch, 82-mile segment from the Navajo refinery to Orla, Texas;
- a 12-inch, 126-mile segment from Orla to outside El Paso, Texas; and
- an 8-inch, 7-mile segment from outside El Paso to our El Paso terminal.

There are two shippers on this pipeline, HFC and Alon. As mentioned above, refined products destined to our El Paso terminal are delivered to common carrier pipelines for transportation to Arizona, northern New Mexico and northern Mexico and to the terminal's truck rack for local delivery by tanker truck.

Artesia, New Mexico to Moriarty, New Mexico

The Artesia to Moriarty refined product pipeline consists of a 60-mile, 12-inch pipeline that was constructed in 1999 and extends from the Navajo refinery Artesia facility to White Lakes Junction, New Mexico, and 155 miles of 8-inch pipeline that was constructed in 1973 and extends from White Lakes Junction to our Moriarty terminal, where it also connects to our Moriarty to Bloomfield pipeline. We own the 12-inch pipeline from Artesia to White Lakes Junction. We lease the White Lakes Junction to Moriarty segment of this pipeline and the Moriarty to Bloomfield pipeline described below, from Mid-America Pipeline Company, LLC under a long-term lease agreement entered into in 1996, which expires in 2017 and has two ten-year extensions at our option. At our Moriarty terminal, volumes shipped on this pipeline can be transported to other markets in the area, including Albuquerque, Santa Fe and West Texas, via tanker truck. The 155-mile White Lakes Junction to Moriarty segment of this pipeline is operated by Mid-America (or its designee). HFC is the only shipper on this pipeline. Currently, we pay a monthly fee (which is subject to adjustments based on changes in the PPI) of $559,000 to Mid-America to lease the White Lakes Junction to Moriarty and Moriarty to Bloomfield pipelines.

Moriarty, New Mexico to Bloomfield, New Mexico

The Moriarty to Bloomfield refined product pipeline was constructed in 1973 and consists of 191 miles of 8-inch pipeline leased from Mid-America. This pipeline serves Western Refining's terminal in Bloomfield and our Bloomfield terminal, which is currently idled. This pipeline is operated by Mid-America (or its designee). HFC is the only shipper on this pipeline.

Big Spring, Texas to Abilene, Texas

The Big Spring to Abilene refined product pipeline was constructed in 1957 and consists of 95 miles of 6-inch pipeline and 5 miles of 8-inch pipeline. This pipeline is used for the shipment of refined products produced at the Big Spring refinery to the Abilene terminal. Alon is the only shipper on this pipeline.

Big Spring, Texas to Wichita Falls, Texas

Segments of the Big Spring to Wichita Falls refined product pipeline were constructed in 1969 and 1989, and consist of 95 miles of 6-inch pipeline and 132 miles of 8-inch pipeline. This pipeline is used for the shipment of refined products produced at the Big Spring refinery to the Wichita Falls terminal. Alon is the only shipper on this pipeline.

Wichita Falls, Texas to Duncan, Oklahoma

The Wichita Falls to Duncan refined product pipeline is a common carrier and is regulated by the FERC. It was constructed in 1958 and consists of 47 miles of 6-inch pipeline. This pipeline is used for the shipment of refined products from the Wichita Falls terminal to Alon’s Duncan terminal, which we do not own. Alon is the only shipper on this pipeline.

Midland, Texas to Orla, Texas
Segments of the Midland to Orla refined product pipeline were constructed in 1928 and 1998, and consist of 50 miles of 10-inch pipeline and 86 miles of 8-inch pipeline. This pipeline is used for the shipment of refined products produced at the Big Spring refinery from Midland to our tank farm at Orla. Alon is the only shipper on this pipeline.

Artesia, New Mexico to Roswell, New Mexico
The 35-mile, 4-inch diameter Artesia to Roswell refined product pipeline is currently idled.

Woods Cross, Utah refined product pipelines
The Woods Cross refined product pipelines consist of three pipeline segments. The Woods Cross to Pioneer segment represents 2 miles of 10-inch pipeline that is also used for product shipments to and through the Pioneer terminal. The Woods Cross to UNEV Pipeline segment consists of 2 miles of 12-inch pipeline and is used for product shipments from HFC's Woods Cross refinery to the UNEV Pipeline origin pump station. The Woods Cross to Chevron Pipeline’s Salt Lake Products Pipeline segment consists of 4 miles of 8-inch pipeline and is used for product shipments from HFC’s Woods Cross refinery to Tesoro's Northwest Pipeline origin station. HFC is the only shipper on these pipelines.

UNEV refined product pipeline
The 427-mile, 12-inch refined products pipeline was completed in early 2012. This pipeline is used for the shipment of refined products from Woods Cross, Utah to terminals in Las Vegas, Nevada and Cedar City, Utah. HFC and Sinclair Transportation Company (“Sinclair”) are the primary shippers on this pipeline.

8” Pipeline from Lovington, New Mexico to Artesia, New Mexico
The 65-mile, 8-inch diameter pipeline was constructed in 1981. This pipeline is used for the shipment of intermediate feedstocks, crude oil and LPGs from the Navajo refinery Lovington facility to its Artesia facility. HFC is the primary shipper on this pipeline.

10” Pipeline from Lovington, New Mexico to Artesia, New Mexico
The 65-mile, 10-inch diameter pipeline was constructed in 1999. This pipeline is used for the shipment of intermediate feedstocks and crude oil from the Navajo refinery Lovington facility to its Artesia facility. HFC is the only shipper on this pipeline.

16” Pipeline from Lovington, New Mexico to Artesia, New Mexico
The 65-mile, 16-inch diameter pipeline was constructed in 2009. This pipeline is used for the shipment of intermediate feedstocks and crude oil from the Navajo refinery Lovington facility to its Artesia facility. This pipeline can also be reversed to deliver crude oil out of the gathering system from Beeson and Barnsdall to either the Lovington facility or the Artesia facility. HFC is the only shipper on this pipeline.

Tulsa, Oklahoma Interconnect Pipelines
Five intermediate product and gas pipelines totaling 7 miles between HFC’s Tulsa East and West refinery facilities were completed in 2011. These pipelines are used in the shipment of gas and liquids between the two facilities.

Lovington / Artesia, New Mexico crude oil pipelines
The crude oil gathering and trunk pipelines deliver crude oil to HFC’s Navajo refinery and consist of 802 miles of 4-inch, 6-inch, 8-inch, and 12-inch diameter pipeline. The crude oil trunk pipelines consist of five pipeline segments that deliver crude oil to the Navajo refinery Lovington facility and seven pipeline segments that deliver crude oil to the Navajo refinery Artesia facility.

The Lovington system crude oil mainlines include five pipeline segments consisting of a 23-mile, 12-inch pipeline from Russell to Lovington, a 20-mile, 8-inch pipeline from Russell to Hobbs, an 11-mile, 6-inch and 8-inch pipeline from Crouch to Lovington, a 20-mile, 8-inch pipeline from Hobbs to Lovington and a 6-mile, 6-inch pipeline from Gaines to Hobbs.

The Artesia system crude oil mainlines include seven pipeline segments consisting of an 11-mile, 6-inch pipeline from Beeson to North Artesia, a 7-mile, 4-inch and 6-inch pipeline from Barnsdall to North Artesia, a 2-mile, 8-inch pipeline from the Barnsdall jumper line to Lovington, a 4-mile, 4-inch pipeline from the Artesia Station to North Artesia, a 6-mile, 8-inch pipeline from North Artesia to Evans Junction and a 1-mile, 6-inch pipeline from Abo to Evans Junction.

We operate a 12-mile, 8-inch pipeline from Evans Junction to Artesia, New Mexico that supplies natural gas to the Navajo refinery Artesia facility. We operate a newly constructed 14 mile, 12-inch pipeline from Beeson station to the Plains Bisti connection. We also reactivated 62 miles of 8-inch pipe for crude movements from Whites City Station to Artesia Station.

Roadrunner Pipeline
The Roadrunner crude oil pipeline connects the Navajo refinery Lovington facility to a West Texas terminal of the Centurion Pipeline that extends to Cushing, Oklahoma. It was constructed in 2009 and consists of 69 miles of 16-inch pipeline. This pipeline is used for the shipment of crude oil from Cushing to the Navajo refinery Lovington facility. It is also reversible to deliver crude from Lovington to Slaughter.

Beeson Pipeline
The Beeson crude oil pipeline delivers crude oil to the Navajo refinery Lovington facility ("Beeson Pipeline"). It was constructed in 2009 and consists of 41 miles of 8-inch pipeline. This pipeline ships crude oil from our crude oil gathering system to the Navajo refinery Lovington facility for processing.

REFINED PRODUCT TERMINALS, LOADING RACKS AND REFINERY TANKAGE

Refined Product Terminals and Loading Racks
Our refined product terminals receive products from pipelines connected to HFC’s refineries and Alon’s Big Spring refinery. We then distribute them to HFC and third parties, who in turn deliver them to end-users and retail outlets. Our terminals are generally complementary to our pipeline assets and serve HFC’s and Alon’s marketing activities and other customers. Terminals play a key role in moving product to the end-user market by providing the following services:

- distribution;
- blending to achieve specified grades of gasoline;
- other ancillary services that include the injection of additives and filtering of jet fuel; and
- storage and inventory management.

Typically, our refined product terminal facilities consist of multiple storage tanks and are equipped with automated truck loading equipment that operates 24 hours a day. This automated system provides for control of security, allocations, and credit and carrier certification by remote input of data by our customers. In addition, nearly all of our terminals are equipped with truck loading racks capable of providing automated blending to individual customer specifications.

Our refined product terminals derive most of their revenues from terminalling fees paid by customers. We charge a fee for transferring refined products from the terminal to trucks or to pipelines connected to the terminal. In addition to terminalling fees, we generate revenues by charging our customers fees for blending, injecting additives, and filtering jet fuel. HFC currently accounts for the substantial majority of our refined product terminal revenues.

The table below sets forth the total average throughput for our refined product terminals in each of the periods presented:

	Years Ended December 31,				
	2014	2013	2012	2011	2010
Refined products terminalled for (bpd):					
HFC	261,888	255,108	271,549	193,645	178,903
Third parties	69,100	63,791	53,456	44,454	39,568
Total	330,988	318,899	325,005	238,099	218,471
Total (mbbls)	120,811	116,398	118,952	86,906	79,742

The following table outlines the locations of our terminals and their storage capacities, number of tanks, supply source, and mode of delivery:

Terminal Location	Storage Capacity (barrels)	Number of Tanks	Supply Source	Mode of Delivery
El Paso, TX	636,000	19	Pipeline/rail	Truck/Pipeline
Moriarty, NM	211,000	9	Pipeline	Truck
Bloomfield, NM (1)	203,000	7	Pipeline	Truck
Tucson, AZ(2)	186,000	9	Pipeline	Truck
Mountain Home, ID(3)	122,000	4	Pipeline	Pipeline
Spokane, WA	384,000	28	Pipeline/Rail	Truck
Abilene, TX	157,000	6	Pipeline	Truck/Pipeline
Wichita Falls, TX	220,000	11	Pipeline	Truck/Pipeline
Las Vegas, NV	381,000	12	Pipeline/Truck	Truck
Cedar City, UT	235,000	7	Pipeline/Rail/Truck	Truck
Orla tank farm	129,000	5	Pipeline	Pipeline
Artesia facility truck rack	N/A	N/A	Refinery	Truck
Lovington facility asphalt truck rack	N/A	N/A	Refinery	Truck
Woods Cross facility truck rack	N/A	N/A	Refinery	Truck/Pipeline
Tulsa West facility truck and rail rack	N/A	N/A	Refinery	Truck/Rail/Pipeline
Tulsa East facility truck and rail racks	N/A	N/A	Refinery	Truck/Rail/Pipeline
Cheyenne facility truck and rail racks	N/A	N/A	Refinery	Truck/Rail
El Dorado facility truck racks	N/A	N/A	Refinery	Truck
Total	2,864,000			

(1) Inactive
(2) The underlying ground at the Tucson terminal is leased.
(3) Handles only jet fuel.

El Paso Terminal

We receive light refined products at this terminal from the Navajo refinery Artesia facility through our Artesia to El Paso and Artesia to Orla to El Paso pipelines and by rail that account for 88% of the volumes at this terminal. We also receive product from the Big Spring refinery that accounted for 12% of the volumes at this terminal in 2014. Refined products received at this terminal are sold locally via the truck rack or transported to our Tucson terminal and other terminals in Phoenix on Kinder Morgan's East System pipeline. Competition in this market includes a refinery and terminal owned by Western Refining, Inc., a joint venture pipeline and terminal owned by ConocoPhillips and NuStar Energy, L.P. ("NuStar").

Moriarty Terminal

We receive light refined products at this terminal from the Navajo refinery Artesia facility through our pipelines. Refined products received at this terminal are sold locally, via the truck rack. HFC is our only customer at this terminal. There are no competing terminals in Moriarty.

Bloomfield Terminal

We historically have received light refined products at this terminal from the Navajo refinery Artesia facility through our pipelines. This terminal is currently idled with no throughput.

Tucson Terminal

We own 100% of the improvements and lease the underlying ground at this terminal. The Tucson terminal receives light refined products from Kinder Morgan's East System pipeline, which transports refined products from the Navajo refinery Artesia facility that it receives at our El Paso terminal. Refined products received at this terminal are sold locally, via the truck rack. Competition in this market includes terminals owned by Kinder Morgan.

Mountain Home Terminal
We receive jet fuel from third parties at this terminal that is transported on Tesoro Logistics' Salt Lake City to Boise, Idaho pipeline. We then transport the jet fuel from the Mountain Home terminal through our 13-mile, 4-inch pipeline to the United States Air Force base outside of Mountain Home. Our pipeline associated with this terminal is the only pipeline that supplies jet fuel to the air base. We are paid a single fee, from the Defense Energy Support Center, for injecting, storing, testing and transporting jet fuel at this terminal.

Spokane Terminal
This terminal is connected to the Woods Cross refinery via a Tesoro Logistics common carrier pipeline. The Spokane terminal is also supplied by rail and truck. Refined products received at this terminal are sold locally, via the truck rack. We have several major customers at this terminal. Other terminals in the Spokane area include terminals owned by ExxonMobil and ConocoPhillips.

Abilene Terminal
This terminal receives refined products from Alon's Big Spring refinery, which accounted for all of its volumes in 2014. Refined products received at this terminal are sold locally via a truck rack or pumped over a 2-mile pipeline to Dyess Air Force Base. Alon is the only customer at this terminal.

Wichita Falls Terminal
This terminal receives refined products from the Alon's Big Spring refinery, which accounted for all of its volumes in 2014. Refined products received at this terminal are sold via a truck rack or shipped via pipeline connections to Alon’s terminal in Duncan, Oklahoma and also to NuStar’s Southlake Pipeline. Alon is the only customer at this terminal.

Las Vegas Terminal
This terminal is owned by UNEV and receives product from HFC and Sinclair shipped through the UNEV Pipeline originating in Woods Cross, Utah. Refined products received at this terminal are sold locally. HFC and Sinclair are the primary customers at this terminal.

Cedar City Terminal
This terminal is owned by UNEV and receives product from HFC and Sinclair shipped through the UNEV Pipeline originating in Woods Cross, Utah. Refined products received at this terminal are sold locally. HFC and Sinclair are the primary customers at this terminal.

Orla Tank Farm
The Orla tank farm was constructed in 1998. It receives refined products from Alon's Big Spring refinery that accounted for all of its volumes in 2014. Refined products received at the tank farm are delivered into our Orla to El Paso pipeline. Alon is the only customer at this tank farm.

Artesia Facility Truck Rack
The truck rack at the Navajo refinery Artesia facility loads light refined products produced at the Navajo refinery onto tanker trucks for delivery to markets in the surrounding area. HFC is the only customer of this truck rack.

Lovington Facility Asphalt Truck Rack
The asphalt loading rack facility at the Lovington refinery loads asphalt produced at the Lovington facility onto tanker trucks. HFC is the only customer of this truck rack.

Woods Cross Facility Truck Rack
The truck rack at the Woods Cross facility loads light refined products produced at the refinery onto tanker trucks for delivery to markets in the surrounding area. HFC is the only customer of this truck rack. HFC also makes transfers to

a common carrier pipeline at this facility.

Tulsa Facilities Truck and Rail Racks

The Tulsa truck and rail loading rack facilities consist of loading racks located at HFC's Tulsa refinery West and East facilities. Loading racks at the Tulsa refinery West facility consist of rail and truck racks that load refined products and lube oil produced at the refinery onto rail cars and tanker trucks. Loading racks at the Tulsa refinery East facility consist of truck and rail racks at which we load refined products and off load crude. The truck racks also load asphalt and LPG.

Cheyenne Facility Truck and Rail Racks
The Cheyenne loading rack facilities consist of light refined products, heavy products and LPG truck and rail racks. These racks load refined products and propane onto tanker trucks for delivery to markets in surrounding areas. Additionally, these facilities include four crude oil LACT units that unload crude oil from tanker trucks.

El Dorado Facility Truck Racks
The El Dorado loading rack facilities consist of a light refined products truck rack and a propane truck rack. These racks load refined products and propane onto tanker trucks for delivery to markets in surrounding areas.

Refinery Tankage
Our refinery tankage consists of on-site tankage at HFC's refineries. Our refinery tankage derives its revenues from fixed fees or throughput charges in providing HFC's refining facilities with approximately 9,400,000 barrels of storage.

The following table outlines the locations of our refinery tankage, storage capacity, tankage type and number of tanks:

Refinery Location	Storage Capacity (barrels)	Tankage Type	Number of Tanks
Artesia , NM	180,000	Crude oil	2
Lovington, NM	309,000	Crude oil	2
Woods Cross, UT	190,000	Crude oil	3
Tulsa, OK	3,272,000	Crude oil and refined product	51
Cheyenne, WY	1,815,000	Crude oil and refined product	51
El Dorado, KS	3,639,000	Refined and intermediate product	84
Total	9,405,000		

PIPELINE AND TERMINAL CONTROL OPERATIONS

All of our pipelines are operated via geosynchronous satellite, microwave, radio and frame relay communication systems from our central control room located in Artesia, New Mexico. We also monitor activity at our terminals from this control room. The control center operates with state-of-the-art System Control and Data Acquisition, or SCADA, systems. Our control center is equipped with computer systems designed to continuously monitor operational data, including refined product and crude oil throughput, flow rates, and pressures. In addition, the control center monitors alarms and throughput balances. The control center operates remote pumps, motors, engines, and valves associated with the delivery of refined products and crude oil. The computer systems are designed to enhance leak-detection capabilities, sound automatic alarms if operational conditions outside of pre-established parameters occur, and provide for remote-controlled shutdown of pump stations on the pipelines. Pump stations and meter-measurement points on the pipelines are linked by satellite or telephone communication systems for remote monitoring and control, which reduces our requirement for full-time on-site personnel at most of these locations.

Item 3. Legal Proceedings
We are a party to various legal and regulatory proceedings, which we believe will not have a material adverse impact on our financial condition, results of operations or cash flows.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for the Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Common Units
Our common limited partner units are traded on the New York Stock Exchange under the symbol "HEP." The following table sets forth the range of the daily high and low sales prices per common unit, cash distributions per common unit and the trading volume of common units for the periods indicated.

Years Ended December 31,	High	Low	Cash Distributions	Trading Volume
2014				
Fourth quarter	$37.44	$28.50	$0.5300	7,685,800
Third quarter	$36.66	$32.50	$0.5225	4,374,200
Second quarter	$36.64	$29.83	$0.5150	7,935,600
First quarter	$34.24	$31.65	$0.5075	3,884,600
2013				
Fourth quarter	$34.32	$29.55	$0.5000	7,533,300
Third quarter	$40.00	$32.54	$0.4925	4,562,500
Second quarter	$40.74	$35.03	$0.4850	7,744,600
First quarter	$36.13	$35.00	$0.4775	11,037,400

The cash distribution for the fourth quarter of 2014 was declared on January 22, 2015, and was paid on February 13, 2015, to all unitholders of record on February 2, 2015.

As of February 18, 2015, we had approximately 17,303 common unitholders, including beneficial owners of common units held in street name.

We consider regular cash distributions to unitholders on a quarterly basis, although there is no assurance as to the future cash distributions since they are dependent upon future earnings, cash flows, capital requirements, financial condition and other factors. See "Liquidity and Capital Resources" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for a discussion of conditions and limitations prohibiting distributions under the Credit Agreement and indentures relating to our senior notes.

Within 45 days after the end of each quarter, we distribute all of our available cash (as defined in our partnership agreement) to unitholders of record on the applicable record date. The amount of available cash generally is all cash on hand at the end of the quarter; less the amount of cash reserves established by our general partner to provide for the proper conduct of our business, comply with applicable laws, any of our debt instruments, or other agreements; or provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters; plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter.

We make distributions in the following manner: 98% to our common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter and any arrearages in payment of the minimum quarterly distributions for any prior quarters, thereafter.

Our general partner, HEP Logistics, is entitled to incentive distributions if the amount we distribute with respect to any quarter exceeds specified target levels presented below:

	Total Quarterly Distribution Target Amount	Marginal Percentage Interest in Distributions	
		Unitholders	General Partner

Minimum quarterly distribution	$0.25	98%	2%
First target distribution	Up to $0.275	98%	2%
Second target distribution	above $0.275 up to $0.3125	85%	15%
Third target distribution	above $0.3125 up to $0.375	75%	25%
Thereafter	Above $0.375	50%	50%

Common Unit Repurchases Made in the Quarter

The following table discloses purchases of our common units made by us or on our behalf for the periods shown below.

Period	Total Number of Units Purchased	Average Price Paid Per Unit	Total Number of Units Purchased as Part of Publicly Announced Plan or Program	Maximum Number of Units that May Yet be Purchased Under a Publicly Announced Plan or Program
October 2014	—	$—	—	$—
November 2014	55,690	$34.48	—	$—
December 2014	—	$—	—	$—
Total for October to December 2014	55,690		—	

We have an incentive plan ("Long-Term Incentive Plan") for employees and non-employee directors who perform services for us. The units reported represent common units purchased in the open market for delivery to recipients of our restricted unit, phantom unit and performance unit awards under our Long-Term Incentive Plan at the time of grant or settlement, as applicable.

Item 6. Selected Financial Data

The following table shows selected financial information for HEP. This table should be read in conjunction with Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements of HEP and related notes thereto included elsewhere in this Form 10-K.

	Years Ended December 31,				
	2014	2013	2012	2011	2010
	(In thousands, except per unit data)				
Statement of Income Data:					
Revenues	$332,545	$305,182	$292,560	$214,268	$182,137
Operating costs and expenses					
Operations (exclusive of depreciation and amortization)	104,801	99,444	89,242	64,521	54,946
Depreciation and amortization	62,166	65,423	57,461	36,958	31,363
General and administrative	10,824	11,749	7,594	6,576	7,719
	177,791	176,616	154,297	108,055	94,028
Operating income	154,754	128,566	138,263	106,213	88,109
Equity in earnings of SLC Pipeline	2,987	2,826	3,364	2,552	2,393
Interest expense	(36,101)	(47,010)	(47,182)	(35,959)	(34,001)
Interest Income	3	161	—	—	7
Loss on early extinguishment of debt	(7,677)	—	(2,979)	—	—
Gain on sale of assets	—	1,810	—	—	—
Other income	82	61	10	17	17
	(40,706)	(42,152)	(46,787)	(33,390)	(31,584)
Income from continuing operations before income taxes	114,048	86,414	91,476	72,823	56,525
State income tax	(235)	(333)	(371)	(234)	(296)
Income from continuing operations	113,813	86,081	91,105	72,589	56,229
Add net loss attributable to Predecessor	—	—	4,200	6,351	70
Allocation of net loss (income) attributable to noncontrolling interests	(8,288)	(6,632)	(1,153)	859	24
Net income attributable to Holly Energy Partners	105,525	79,449	94,152	79,799	56,323
Less general partner interest in net income, including incentive distributions(1)	34,667	27,523	22,450	16,806	12,084
Limited partners' interest in net income	$70,858	$51,926	$71,702	$62,993	$44,239
Limited partners' per unit interest in net income – basic and diluted(1)	$1.20	$0.88	$1.29	$1.38	$1.00
Distributions per limited partner unit	$2.08	$1.96	$1.84	$1.74	$1.66
Other Financial Data:					
Cash flows from operating activities	$186,640	$183,080	$161,149	$98,907	$104,736
Cash flows from investing activities	$(79,696)	$(49,070)	$(42,599)	$(206,174)	$(142,051)
Cash flows from financing activities	$(110,466)	$(132,895)	$(119,682)	$105,584	$35,856
EBITDA(2)	$211,701	$192,054	$194,242	$149,766	$122,089
Distributable cash flow(3)	$172,718	$146,579	$153,125	$100,295	$91,054
Maintenance capital expenditures(4)	$4,616	$8,683	$5,649	$5,415	$4,487
Expansion capital expenditures	75,343	43,418	37,212	200,894	137,442
Total capital expenditures	$79,959	$52,101	$42,861	$206,309	$141,929
Balance Sheet Data (at period end):					

Net property, plant and equipment	$980,479	$957,814	$960,499	$683,793	$553,233
Total assets	$1,401,555	$1,382,508	$1,399,196	$913,263	$779,035
Long-term debt(5)	$867,579	$807,630	$605,888	$491,648	$390,827
Total liabilities	$986,111	$915,574	$661,518	$548,402	$425,633
Total equity(6)	$415,444	$466,934	$737,678	$364,861	$353,402

(1) Net income is allocated between limited partners and the general partner interest in accordance with the provisions of the partnership agreement. Net income allocated to the general partner includes incentive distributions declared subsequent to quarter end. Net income attributable to the limited partners is divided by the weighted average limited partner units outstanding in computing the limited partners' per unit interest in net income.

(2) Earnings before interest, taxes, depreciation and amortization ("EBITDA") is calculated as net income attributable to Holly Energy Partners plus (i) interest expense net of interest income, (ii) state income tax and (iii) depreciation and amortization excluding amounts related to previous owners ("Predecessor"). EBITDA is not a calculation based upon generally accepted accounting principles ("GAAP"). However, the amounts included in the EBITDA calculation are derived from amounts included in our consolidated financial statements, with the exception of EBITDA from discontinued operations. EBITDA should not be considered as an alternative to net income or operating income, as an indication of our operating performance or as an alternative to operating cash flow as a measure of liquidity. EBITDA is not necessarily comparable to similarly titled measures of other companies. EBITDA is presented here because it is a widely used financial indicator used by investors and analysts to measure performance. EBITDA is also used by our management for internal analysis and as a basis for compliance with financial covenants.

Set forth below is our calculation of EBITDA.

	Years Ended December 31,				
	2014	2013	2012	2011	2010
	(In thousands)				
Income from continuing operations attributable to HEP	$105,525	$79,449	$94,152	$79,799	$56,323
Add (subtract):					
Interest expense	34,280	44,041	40,141	34,706	30,453
Interest income	(3)	(161)	—	—	(7)
Amortization of discount and deferred debt issuance costs	1,821	2,120	1,946	1,212	1,008
Loss on early extinguishment of debt	7,677	—	2,979	—	—
Amortization of unrealized loss attributable to discontinued cash flow hedge	—	849	5,095	41	2,540
State income tax	235	333	371	234	296
Depreciation and amortization	62,166	65,423	57,461	36,958	31,363
Predecessor depreciation and amortization	—	—	(7,903)	(3,184)	113
EBITDA	$211,701	$192,054	$194,242	$149,766	$122,089

(3) Distributable cash flow is not a calculation based upon GAAP. However, the amounts included in the calculation are derived from amounts presented in our consolidated financial statements, with the general exceptions of a billed crude revenue settlement, maintenance capital expenditures and distributable cash flow from discontinued operations. Distributable cash flow should not be considered in isolation or as an alternative to net income or operating income as an indication of our operating performance or as an alternative to operating cash flow as a measure of liquidity. Distributable cash flow is not necessarily comparable to similarly titled measures of other companies. Distributable cash flow is presented here because it is a widely accepted financial indicator used by investors to compare partnership performance. Also, it is used by management for internal analysis and for our performance units. We believe this measure provides investors an enhanced perspective of the operating performance of our assets and the cash our business is generating.

Set forth below is our calculation of distributable cash flow.

	Years Ended December 31,				
	2014	2013	2012	2011	2010
	(In thousands)				
Income from continuing operations attributable to HEP	$105,525	$79,449	$94,152	$79,799	$56,323
Add (subtract):					
Depreciation and amortization	62,166	65,423	57,461	36,958	31,363
Predecessor depreciation and amortization	—	—	(7,903)	(3,184)	113

Amortization of discount and deferred debt issuance costs	1,821	2,120	1,946	1,212	1,008
Amortization of unrealized loss attributable to discontinued cash flow hedge	—	849	5,095	41	2,540
Loss on early extinguishment of debt	7,677	—	2,979	—	—
Increase (decrease) in deferred revenue related to minimum revenue commitments	(2,503)	3,686	462	(6,405)	2,035
Maintenance capital expenditures [4]	(4,616)	(8,683)	(5,649)	(5,415)	(4,487)
Crude revenue settlement	—	918	3,670	(4,588)	—
Other non-cash adjustments	2,648	2,817	912	1,877	2,159
Distributable cash flow	$172,718	$146,579	$153,125	$100,295	$91,054

(4) Maintenance capital expenditures are capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity of our assets and to extend their useful lives. Maintenance capital expenditures include expenditures required to maintain equipment reliability, tankage and pipeline integrity, safety and to address environmental regulations.

(5) Includes $571 million, $363 million, $200 million, $159 million and $206 million in Credit Agreement advances that were classified as long-term debt at December 31, 2014, 2013, 2012, 2011 and 2010, respectively.

(6) As a master limited partnership, we distribute our available cash, which historically has exceeded our net income because depreciation and amortization expense represents a non-cash charge against income. The result is a decline in partners' equity since our regular quarterly distributions have exceeded our quarterly net income. Additionally, if the assets contributed and acquired from HFC while under common control of HFC had been acquired from third parties, our acquisition cost in excess of HFC's basis in the transferred assets of $305.3 million would have been recorded in our financial statements as increases to our properties and equipment and intangible assets instead of decreases to partners' equity.

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

This Item 7, including but not limited to the sections on "Liquidity and Capital Resources," contains forward-looking statements. See "Forward-Looking Statements" at the beginning of Part I and Item 1A. "Risk Factors." In this document, the words "we," "our," "ours" and "us" refer to HEP and its consolidated subsidiaries or to HEP or an individual subsidiary and not to any other person.

OVERVIEW

HEP is a Delaware limited partnership. We own and operate petroleum product and crude oil pipelines and terminal, tankage and loading rack facilities that support HFC's refining and marketing operations in the Mid-Continent, Southwest and Rocky Mountain regions of the United States and Alon's refinery in Big Spring, Texas. At December 31, 2014, HFC owned a 39% interest in us including the 2% general partnership interest. Additionally, we own a 75% interest in UNEV, the owner of a pipeline running from Woods Cross, Utah to Las Vegas, Nevada and related products terminals and a 25% joint venture interest in the SLC Pipeline, a 95-mile intrastate crude oil pipeline system that serves refineries in the Salt Lake City, Utah area.

We generate revenues by charging tariffs for transporting petroleum products and crude oil through our pipelines, by charging fees for terminalling and storing refined products and other hydrocarbons and providing other services at our storage tanks and terminals. We do not take ownership of products that we transport, terminal or store, and therefore we are not directly exposed to changes in commodity prices.

On January 16, 2013, a two-for-one unit split was paid in the form of a common unit distribution for each issued and outstanding common unit to all unitholders of record on January 7, 2013. All references to unit and per unit amounts in this document and related disclosures have been adjusted to reflect the effect of the unit split for all prior periods presented.

In March 2013, we closed on a public offering of 1,875,000 of our common units. Additionally, an affiliate of HFC, as a selling unitholder, closed on a public sale of 1,875,000 of its HEP common units for which we did not receive any proceeds. We used our net proceeds of $73.4 million to repay indebtedness incurred under our credit facility and for general partnership purposes. Amounts repaid under our credit facility may be reborrowed from time to time, and we intend to reborrow certain amounts to fund capital expenditures.

In March 2014, we redeemed the $150 million aggregate principal amount of 8.25% Senior Notes maturing March 2018 at a redemption cost of $156.2 million, at which time we recognized a $7.7 million early extinguishment loss consisting of a $6.2 million debt redemption premium and unamortized discount and financing costs of $1.5 million. We funded the redemption with borrowings under our Credit Agreement.

We believe the growth of crude production in the Permian Basin and throughout the Mid-Continent and refining economics should support high utilization rates for the refineries we serve, which in turn will support volumes in our product pipelines, crude gathering system and terminals.

UNEV Pipeline Interest Acquisition

Under the terms of the transaction to acquire HFC's 75% interest in UNEV, we issued to HFC a Class B unit comprising a noncontrolling equity interest in a wholly-owned subsidiary subject to redemption to the extent that HFC is entitled to a 50% interest in our share of annual UNEV earnings before interest, income taxes, depreciation, and amortization above $30 million beginning July 1, 2016, and ending in June 2032, subject to certain limitations. However, to the extent earnings thresholds are not achieved, no redemption payments are required. Contemporaneously with this transaction, HFC (our general partner) agreed to forego its right to incentive distributions of up to $1.25 million per quarter over twelve consecutive quarterly periods following the closing of the transaction and up to an additional four quarters in certain circumstances. In connection with the transaction, we entered into 15-year throughput agreements with shippers containing minimum annual revenue commitments to us of $27 million.

Agreements with HFC and Alon

We serve HFC's refineries under long-term pipeline and terminal, tankage and throughput agreements expiring from 2019 to 2026. Under these agreements, HFC agreed to transport, store and throughput volumes of refined product and crude oil on our pipelines and terminal, tankage and loading rack facilities that result in minimum annual payments to us. Additionally, such agreements require HFC to reimburse us for certain costs. These minimum annual payments or revenues are subject to annual tariff rate adjustments on July 1, based on the PPI or FERC index. As of December 31, 2014, these agreements with HFC will result in minimum annualized payments to us of $231.6 million.

If HFC fails to meet its minimum volume commitments under the agreements in any quarter, it will be required to pay us in cash the amount of any shortfall by the last day of the month following the end of the quarter. Under certain of the agreements, a shortfall payment may be applied as a credit in the following four quarters after minimum obligations are met.

We have a pipelines and terminals agreement with Alon expiring in 2020 under which Alon has agreed to transport on our pipelines and throughput through our terminals volumes of refined products that result in a minimum level of annual revenue that also is subject to annual tariff rate adjustments. We also have a capacity lease agreement under which we lease Alon space on our Orla to El Paso pipeline for the shipment of refined product. The terms under this lease agreement expire beginning in 2018 through 2022. As of December 31, 2014, these agreements with Alon will result in minimum annualized payments to us of $32.1 million.

A significant reduction in revenues under these agreements could have a material adverse effect on our results of operations.

Under certain provisions of the Omnibus Agreement that we have with HFC, we pay HFC an annual administrative fee ($2.3 million in 2014 and currently $2.4 million), for the provision by HFC of various general and administrative services to us on behalf of HLS. This fee does not include the salaries of personnel employed by HFC who perform services for us or the cost of their employee benefits, which are separately charged to us by HFC. We also reimburse HFC for direct expenses they incur on our behalf.

Under HLS's secondment arrangement with HFC, certain employees of HFC are seconded to HLS to provide operational and maintenance services for certain of our pipelines and tankage assets at the El Dorado and Cheyenne refineries, and HLS reimburses HFC for its prorated portion of the wages, benefits, and other costs of these employees for our benefit.

- 40 -

RESULTS OF OPERATIONS

Income, Distributable Cash Flow and Volumes

The following tables present income, distributable cash flow and volume information for the years ended December 31, 2014, 2013 and 2012.

	Years Ended December 31,		Change from
	2014	2013	2013
	(In thousands, except per unit data)		
Revenues			
Pipelines:			
Affiliates—refined product pipelines	$77,852	$66,441	$11,411
Affiliates—intermediate pipelines	29,813	25,397	4,416
Affiliates—crude pipelines	56,804	48,749	8,055
	164,469	140,587	23,882
Third parties—refined product pipelines	43,377	41,837	1,540
	207,846	182,424	25,422
Terminals, tanks and loading racks:			
Affiliates	110,726	111,781	(1,055)
Third parties	13,973	10,977	2,996
	124,699	122,758	1,941
Total revenues	332,545	305,182	27,363
Operating costs and expenses			
Operations (exclusive of depreciation and amortization)	104,801	99,444	5,357
Depreciation and amortization	62,166	65,423	(3,257)
General and administrative	10,824	11,749	(925)
	177,791	176,616	1,175
Operating income	154,754	128,566	26,188
Equity in earnings of SLC Pipeline	2,987	2,826	161
Interest expense, including amortization	(36,101)	(47,010)	10,909
Interest income	3	161	(158)
Loss on early extinguishment of debt	(7,677)	—	(7,677)
Gain on sale of assets	—	1,810	(1,810)
Other	82	61	21
	(40,706)	(42,152)	1,446
Income before income taxes	114,048	86,414	27,634
State income tax	(235)	(333)	98
Net income	113,813	86,081	27,732
Allocation of net loss income attributable to noncontrolling interests	(8,288)	(6,632)	(1,656)
Net income attributable to Holly Energy Partners	105,525	79,449	26,076
General partner interest in net income, including incentive distributions [1]	(34,667)	(27,523)	(7,144)
Limited partners' interest in net income	$70,858	$51,926	$18,932
Limited partners' earnings per unit—basic and diluted [1]	$1.20	$0.88	$0.32
Weighted average limited partners' units outstanding	58,657	58,246	411
EBITDA [2]	$211,701	$192,054	$19,647
Distributable cash flow [3]	$172,718	$146,579	$26,139

Volumes (bpd)

Pipelines:

Affiliates—refined product pipelines	119,156	107,493	11,663
Affiliates—intermediate pipelines	138,258	128,475	9,783
Affiliates—crude pipelines	199,600	161,391	38,209
	457,014	397,359	59,655
Third parties—refined product pipelines	64,055	63,337	718
	521,069	460,696	60,373
Terminals and loading racks:			
Affiliates	261,888	255,108	6,780
Third parties	69,100	63,791	5,309
	330,988	318,899	12,089
Total for pipelines and terminal assets (bpd)	852,057	779,595	72,462

	Years Ended December 31, 2013	2012	Change from 2012
	(In thousands, except per unit data)		
Revenues			
Pipelines:			
Affiliates—refined product pipelines	$66,441	$67,682	$(1,241)
Affiliates—intermediate pipelines	25,397	28,540	(3,143)
Affiliates—crude pipelines	48,749	45,888	2,861
	140,587	142,110	(1,523)
Third parties—refined product pipelines	41,837	37,521	4,316
	182,424	179,631	2,793
Terminals, tanks and loading racks:			
Affiliates	111,781	103,472	8,309
Third parties	10,977	9,457	1,520
	122,758	112,929	9,829
Total revenues	305,182	292,560	12,622
Operating costs and expenses			
Operations (exclusive of depreciation and amortization)	99,444	89,242	10,202
Depreciation and amortization	65,423	57,461	7,962
General and administrative	11,749	7,594	4,155
	176,616	154,297	22,319
Operating income	128,566	138,263	(9,697)
Equity in earnings of SLC Pipeline	2,826	3,364	(538)
Interest expense, including amortization	(47,010)	(47,182)	172
Interest income	161	—	161
Loss on early extinguishment of debt	—	(2,979)	2,979
Gain on sale of assets	1,810	—	1,810
Other expense	61	10	51
	(42,152)	(46,787)	4,635
Income before income taxes	86,414	91,476	(5,062)
State income tax	(333)	(371)	38
Net income	86,081	91,105	(5,024)
Allocation of net loss attributable to Predecessors	—	4,200	(4,200)
Allocation of net income attributable to noncontrolling interests	(6,632)	(1,153)	(5,479)
Net income attributable to Holly Energy Partners	79,449	94,152	(14,703)
General partner interest in net income, including incentive distributions [1]	(27,523)	(22,450)	(5,073)
Limited partners' interest in net income	$51,926	$71,702	$(19,776)
Limited partners' earnings per unit—basic and diluted [1]	$0.88	$1.29	$(0.41)
Weighted average limited partners' units outstanding	58,246	55,696	2,550
EBITDA [2]	$192,054	$194,242	$(2,188)
Distributable cash flow [3]	$146,579	$153,125	$(6,546)
Volumes (bpd)			
Pipelines:			
Affiliates—refined product pipelines	107,493	107,509	(16)
Affiliates—intermediate pipelines	128,475	127,169	1,306
Affiliates—crude pipelines	161,391	171,040	(9,649)
	397,359	405,718	(8,359)

Third parties—refined product pipelines	63,337	63,152	185	
	460,696	468,870	(8,174	)
Terminals and loading racks:				
Affiliates	255,108	271,549	(16,441	)
Third parties	63,791	53,456	10,335	
	318,899	325,005	(6,106	)
Total for pipelines and terminal assets (bpd)	779,595	793,875	(14,280	)

(1) Net income attributable to HEP is allocated between limited partners and the general partner interest in accordance with the provisions of the partnership agreement. HEP net income allocated to the general partner includes incentive distributions that are declared subsequent to quarter end. After the amount of incentive distributions is allocated to the general partner, the remaining net income attributable to HEP is allocated to the partners based on their weighted average ownership percentage during the period.

(2) EBITDA is calculated as net income attributable to Holly Energy Partners plus (i) interest expense, net of interest income, (ii) state income tax and (iii) depreciation and amortization, excluding amounts related to Predecessor. EBITDA is not a calculation based upon GAAP. However, the amounts included in the EBITDA calculation are derived from amounts included in our consolidated financial statements, with the exception of EBITDA from discontinued operations. EBITDA should not be considered as an alternative to net income or operating income, as an indication of our operating performance or as an alternative to operating cash flow as a measure of liquidity. EBITDA is not necessarily comparable to similarly titled measures of other companies. EBITDA is presented here because it is a widely used financial indicator used by investors and analysts to measure performance. EBITDA is also used by our management for internal analysis and as a basis for compliance with financial covenants. See our calculation of EBITDA under Item 6, "Selected Financial Data."

(3) Distributable cash flow is not a calculation based upon GAAP. However, the amounts included in the calculation are derived from amounts presented in our consolidated financial statements, with the general exceptions of a billed crude revenue settlement, maintenance capital expenditures and distributable cash flow from discontinued operations. Distributable cash flow should not be considered in isolation or as an alternative to net income or operating income as an indication of our operating performance or as an alternative to operating cash flow as a measure of liquidity. Distributable cash flow is not necessarily comparable to similarly titled measures of other companies. Distributable cash flow is presented here because it is a widely accepted financial indicator used by investors to compare partnership performance. Also it is used by management for internal analysis and for our performance units. We believe that this measure provides investors an enhanced perspective of the operating performance of our assets and the cash our business is generating. See our calculation of distributable cash flow under Item 6, "Selected Financial Data."

Results of Operations — Year Ended December 31, 2014 Compared with Year Ended December 31, 2013

Summary

Net income attributable to HEP for the year ended December 31, 2014, was $105.5 million, a $26.1 million increase compared to the year ended December 31, 2013. This increase in earnings is due principally to higher pipeline and terminal volumes and annual tariff increases, as well as decreased interest expense due to the early retirement of our 8.25% Senior Notes in March 2014.

Revenues for the year ended December 31, 2014, include the recognition of $12.0 million of prior shortfalls billed to shippers in 2013. As of December 31, 2014, deferred revenue on our consolidated balance sheet related to shortfalls billed was $9.3 million. Such deferred revenue will be recognized in earnings either as (a) payment for shipments in excess of guaranteed levels, if and to the extent the pipeline system will have the necessary capacity to provide for shipments in excess of guaranteed levels, or (b) when shipping rights expire unused over the contractual make-up period.

Revenues

Total revenues for the year ended December 31, 2014, were $332.5 million, a $27.4 million increase compared to the year ended December 31, 2013. The revenue increase was due to the effect of annual tariff increases, increased pipeline shipments and a $4.2 million increase in previously deferred revenue realized. Overall pipeline volumes were up 13% compared to the year ended December 31, 2013, largely due to low volumes in 2013 resulting from a major maintenance turnaround at HFC's Navajo refinery in the first quarter of 2013 as well as the reduced crude throughput at HFC's Navajo refinery during the fourth quarter of 2013.

Revenues from our refined product pipelines were $121.2 million, an increase of $13.0 million compared to the year ended December 31, 2013, primarily due to increased volumes and the effect of a $2.1 million increase in deferred revenue realized. Shipments averaged 183.2 thousand barrels per day ("mbpd") compared to 170.8 mbpd for 2013.

Revenues from our intermediate pipelines were $29.8 million, an increase of $4.4 million on shipments averaging 138.3 mbpd compared to 128.5 mbpd for the year ended December 31, 2013. The increase in revenue is due to the effects of a $2.2 million increase in deferred revenue realized and increased volumes on intermediate pipeline segments.

Revenues from our crude pipelines were $56.8 million, an increase of $8.1 million on shipments averaging 199.6 mbpd compared to 161.4 mbpd for the year ended December 31, 2013. Revenues increased due to the annual tariff increases and higher volumes resulting from the New Mexico gathering system expansion. In addition, volumes were lower in 2013 due to the turnaround at HFC's Navajo refinery and the fourth quarter 2013 processing constraints at HFC's Navajo refinery.

Revenues from terminal, tankage and loading rack fees were $124.7 million, an increase of $1.9 million compared to the year ended December 31, 2013. The increase in revenues is due principally to increased volumes. Refined products terminalled in our facilities increased to an average of 331.0 mbpd compared to 318.9 mbpd for 2013.

Operations Expense
Operations expense for the year ended December 31, 2014, increased by $5.4 million compared to the year ended December 31, 2013. This increase is due to higher maintenance costs and environmental accruals.

Depreciation and Amortization
Depreciation and amortization for the year ended December 31, 2014, decreased by $3.3 million compared to the year ended December 31, 2013, due principally to lower asset abandonment charges related to tankage permanently removed from service.

General and Administrative
General and administrative costs for the year ended December 31, 2014, decreased by $0.9 million compared to the year ended December 31, 2013, due to lower costs for professional services.

Equity in Earnings of SLC Pipeline
Our equity in earnings of the SLC Pipeline was $3.0 million and $2.8 million for the years ended December 31, 2014 and 2013.

Interest Expense
Interest expense for the year ended December 31, 2014, totaled $36.1 million, a decrease of $10.9 million compared to the year ended December 31, 2013. Our aggregate effective interest rate was 4.3% and 5.7% for the years ended December 31, 2014 and 2013, respectively.

Loss on Early Extinguishment of Debt
We recognized a charge of $7.7 million upon the early extinguishment of our 8.25% Senior Notes for the year ended December 31, 2014. This charge related to the premium paid to noteholders upon their tender of an aggregate principal amount of $150.0 million and related financing costs that were previously deferred.

Gain on Sale of Assets
The gain on the sale of assets for the year ended December 31, 2013, of $1.8 million is comprised of a gain of $2.0 million on the sale of property in El Paso, Texas, partially offset by a $0.2 million loss from the sale of our 50% ownership interest in product terminals located in Boise and Burley, Idaho.

State Income Tax
We recorded state income tax expense of $235,000 and $333,000 for the years ended December 31, 2014 and 2013, respectively, which is solely attributable to the Texas margin tax. Due to a statutory change in June 2013, there was a one-time charge of $366,000 to establish a deferred tax liability. We are subject to the Texas margin tax based on our Texas sourced taxable margin.

Results of Operations—Year Ended December 31, 2013 Compared with Year Ended December 31, 2012

Summary

Net income attributable to HEP for the year ended December 31, 2013, was $79.4 million, a $14.7 million decrease compared to the year ended December 31, 2012. This decrease in earnings is due principally to increased operating costs and expenses, including higher depreciation resulting from asset abandonment charges related to tankage permanently removed from service, combined with higher allocations of income to noncontrolling interests. Overall revenues increased but did not keep pace with the cost increases as pipeline volumes supporting HFC's Navajo refinery were reduced in 2013 as the refinery experienced a planned turnaround in the first quarter and unplanned refinery downtime in the fourth quarter. Limited partners' per unit interest in earnings decreased from $1.29 per unit in 2012 to $0.88 per unit in 2013 due to the income decreases combined with higher incentive distributions to the general partner.

Revenues for the year ended December 31, 2013, include the recognition of $7.8 million of prior shortfalls billed to shippers in 2012. As of December 31, 2013, deferred revenue on our consolidated balance sheet related to shortfalls billed was $12.0 million.

Revenues
Total revenues for the year ended December 31, 2013, were $305.2 million, a $12.6 million increase compared to the year ended December 31, 2012. The revenue increase was due to the effect of annual tariff increases, higher cost reimbursement receipts from HFC and a $1.5 million increase in previously deferred revenue realized. Overall pipeline volumes were down 2% compared to the year ended December 31, 2012.

Revenues from our refined product pipelines were $108.3 million, an increase of $3.1 million compared to the year ended December 31, 2012, primarily due to the effects of a $3.3 million increase in previously deferred revenue realized and annual tariff increases. Shipments averaged 170.8 mbpd compared to 170.7 mbpd for 2012.

Revenues from our intermediate pipelines were $25.4 million, a decrease of $3.1 million on shipments averaging 128.5 mbpd compared to 127.2 mbpd for the year ended December 31, 2012. The decrease in revenue is due to the effects of a $1.8 million decrease in deferred revenue realized and reduced volumes on certain high tariff pipeline segments.

Revenues from our crude pipelines were $48.7 million, an increase of $2.9 million on shipments averaging 161.4 mbpd compared to 171.0 mbpd for the year ended December 31, 2012. Although crude oil pipeline shipments were down, revenues increased due to the annual tariff increases and minimum billings on certain pipeline segments.

Revenues from terminal, tankage and loading rack fees were $122.8 million, an increase of $9.8 million compared to year ended December 31, 2012. The increase in revenues is due to annual fee increases and higher tank cost reimbursement receipts from HFC. Refined products terminalled in our facilities decreased to an average of 318.9 mbpd compared to 325.0 mbpd for 2012.

Operations Expense
Operations expense for the year ended December 31, 2013, increased by $10.2 million compared to the year ended December 31, 2012. This increase is due to higher maintenance costs, environmental accruals, employee costs and property taxes, offset by a $3.5 million net tax refund related to payroll costs covering a multi-year period.

Depreciation and Amortization
Depreciation and amortization for the year ended December 31, 2013, increased by $8.0 million compared to the year ended December 31, 2012 due principally to asset abandonment charges related to tankage permanently removed from service.

General and Administrative
General and administrative costs for the year ended December 31, 2013, increased by $4.2 million compared to the year ended December 31, 2012, due to increased employee costs.

Equity in Earnings of SLC Pipeline
Our equity in earnings of the SLC Pipeline was $2.8 million and $3.4 million for the years ended December 31, 2013 and 2012, respectively.

Interest Expense
Interest expense for the year ended December 31, 2013, totaled $47.0 million, a decrease of $0.2 million compared to the year ended December 31, 2012. Our aggregate effective interest rate was 5.7% and 6.5% for the years ended December 31, 2013 and 2012, respectively.

Loss on Early Extinguishment of Debt

We recognized a charge of $3.0 million upon the early extinguishment of our 6.25% Senior Notes ("6.25% Senior Notes") for the year ended December 31, 2012. This charge related to the premium paid to noteholders upon their tender of an aggregate principal amount of $185.0 million and related financing costs that were previously deferred.

Gain on Sale of Assets

The gain on the sale of assets for the year ended December 31, 2013, of $1.8 million is comprised of a gain of $2.0 million on the sale of property in El Paso, Texas, partially offset by a $0.2 million loss from the sale of our 50% ownership interest in product terminals located in Boise and Burley, Idaho.

State Income Tax
We recorded state income tax expense of $333,000 and $371,000 for the years ended December 31, 2013 and 2012, respectively, which is solely attributable to the Texas margin tax. We are subject to the Texas margin tax based on our Texas sourced taxable margin. Due to a statutory change that was enacted in June 2013, we are now able to deduct additional expenses which will result in lower cash taxes to HEP in the current and future years.

LIQUIDITY AND CAPITAL RESOURCES

Overview
Our $650 million senior secured revolving credit facility (the "Credit Agreement") expires in November 2018 and is available to fund capital expenditures, investments, acquisitions, distribution payments and working capital and for general partnership purposes. It is also available to fund letters of credit up to a $50 million sub-limit.

During the year ended December 31, 2014, we received advances totaling $642.3 million and repaid $434.3 million, resulting in a net increase of $208.0 million under the Credit Agreement and an outstanding balance of $571.0 million at December 31, 2014. We have no letters of credit outstanding under the Credit Agreement at December 31, 2014. If any particular lender under the Credit Agreement could not honor its commitment, we believe the unused capacity that would be available from the remaining lenders would be sufficient to meet our borrowing needs. Additionally, we review publicly available information on the lenders in order to monitor their financial stability and assess their ongoing ability to honor their commitments under the Credit Agreement. We do not expect to experience any difficulty in the lenders' ability to honor their respective commitments, and if it were to become necessary, we believe there would be alternative lenders or options available.

Under our registration statement filed with the SEC using a "shelf" registration process, we currently have the ability to raise up to $2.0 billion by offering securities, through one or more prospectus supplements that would describe, among other things, the specific amounts, prices and terms of any securities offered and how the proceeds would be used. Any proceeds from the sale of securities would be used for general business purposes, which may include, among other things, funding acquisitions of assets or businesses, working capital, capital expenditures, investments in subsidiaries, the retirement of existing debt and/or the repurchase of common units or other securities.

We believe our current cash balances, future internally generated funds and funds available under the Credit Agreement will provide sufficient resources to meet our working capital liquidity needs for the foreseeable future.

In February, May, August and November 2014, we paid regular quarterly cash distributions of $0.5000, $0.5075, $0.5150 and $0.5225, respectively, on all units in an aggregate amount of $154.7 million. Included in this aggregate amount were $31.5 million of incentive distribution payments to the general partner.

Contemporaneously with our UNEV Pipeline interest acquisition on July 12, 2012, HFC (our general partner) agreed to forego its right to incentive distributions of $1.25 million per quarter over twelve consecutive quarterly periods following the close of the transaction and up to an additional four quarters in certain circumstances.

Cash and cash equivalents decreased by $3.5 million during the year ended December 31, 2014. The cash flows provided by operating activities of $186.6 million were less than the cash flows used for financing and investing activities of $110.5 million and $79.7 million, respectively. Working capital increased by $9.7 million to $3.1 million at December 31, 2014 from a deficit of $6.6 million at December 31, 2013.

Cash Flows—Operating Activities
Year Ended December 31, 2014 Compared with Year Ended December 31, 2013

Cash flows from operating activities increased by $3.6 million from $183.1 million for the year ended December 31, 2013, to $186.6 million for the year ended December 31, 2014. This increase is due principally to $12.1 million of greater cash receipts for services performed in the year ended December 31, 2014, as compared to the prior year, partially offset by payments made for increased operating expenses.

Our major shippers are obligated to make deficiency payments to us if they do not meet their minimum volume shipping obligations. Under certain agreements with these shippers, they have the right to recapture these amounts if future volumes exceed minimum levels. We billed $12.0 million during the year ended December 31, 2013, related to shortfalls that subsequently expired without recapture and were recognized as revenue during the year ended December 31, 2014. Another $9.3 million is included as deferred revenue on our balance sheet at December 31, 2014, related to shortfalls billed during the year ended December 31, 2014.

Year Ended December 31, 2013 Compared with Year Ended December 31, 2012
Cash flows from operating activities increased by $21.9 million from $161.1 million for the year ended December 31, 2012, to $183.1 million for the year ended December 31, 2013. This increase is due principally to $30.7 million of greater cash receipts for services performed in the year ended December 31, 2013, as compared to the prior year, partially offset by payments made for increased operating expenses.

We billed $9.3 million during the year ended December 31, 2012, related to shortfalls that subsequently expired without recapture and were recognized as revenue during the year ended December 31, 2013. Another $12.0 million was included in our accounts receivable at December 31, 2013 related to shortfalls that occurred during the year ended December 31, 2013

Cash Flows—Investing Activities
Year Ended December 31, 2014 Compared with Year Ended December 31, 2013
Cash flows used for investing activities increased by $30.6 million from $49.1 million for the year ended December 31, 2013, to $79.7 million for the year ended December 31, 2014. During the years ended December 31, 2014 and 2013, we invested $80.0 million and $52.1 million in additions to properties and equipment, respectively. During the year ended December 31, 2013, we received $2.7 million proceeds from the sale of assets.

Year Ended December 31, 2013 Compared with Year Ended December 31, 2012
Cash flows used for investing activities increased by $6.5 million from $42.6 million for the year ended December 31, 2012 to $49.1 million for the year ended December 31, 2013. During the years ended December 31, 2013 and 2012, we invested $52.1 million and $42.9 million in additions to properties and equipment, respectively. During the year ended December 31, 2013, we received $2.7 million proceeds from the sale of assets. Distributions in excess of equity in earnings of the SLC Pipeline was $0.3 million for the years ended December 31, 2013 and 2012.

Cash Flows—Financing Activities
Year Ended December 31, 2014 Compared with Year Ended December 31, 2013
Cash flows used for financing activities were $110.5 million for the year ended December 31, 2014, compared to $132.9 million for the year ended December 31, 2013, a decrease of $22.4 million. During the year ended December 31, 2014, we received $642.3 million and repaid $434.3 million in advances under the Credit Agreement and paid $156.2 million to redeem the 8.25% Senior Notes. Additionally, we paid $154.7 million in regular quarterly cash distributions to our general and limited partners, paid $4.0 million to our noncontrolling interest and paid $3.6 million for the purchase of common units for recipients of our incentive grants. During the year ended December 31, 2013, we received $310.6 million and repaid $368.6 million in advances under the Credit Agreement and received net proceeds of $73.4 million from the common unit public offering. We paid $139.5 million in regular quarterly cash distributions to our general and limited partners, and paid $3.1 million to our noncontrolling interest. We received $1.5 million from our general partner, paid $1.3 million in financing costs to amend our Credit Agreement and paid $5.6 million for the purchase of common units for recipients of our incentive grants.

Year Ended December 31, 2013 Compared with Year Ended December 31, 2012
Cash flows used for financing activities were $132.9 million for the year ended December 31, 2013, compared to $119.7 million for the year ended December 31, 2012, an increase of $13.2 million. During the year ended December 31, 2013, we received $310.6 million and repaid $368.6 million in advances under the Credit Agreement, received net proceeds of $73.4 million from the common unit public offering and $1.5 million from the general partner to maintain its 2% interest. Additionally, we paid $139.5 million in regular quarterly cash distributions to our general and limited partners, and paid $5.6 million for the purchase of common units for recipients of our incentive grants. Also, we paid $3.1 million to our noncontrolling interest and paid $1.3 million in financing costs to amend our Credit Facility. During the year ended December 31, 2012, we received $587.0 million and repaid $366.0 million in advances under

the Credit Agreement, received net proceeds of $294.8 million from the issuance of our 6.5% Senior Notes and repaid $260.2 million of our notes. We paid HFC $260.9 million as partial consideration for the acquisition of HFC's 75% interest in UNEV. Additionally, we paid $122.8 million in regular quarterly cash distributions to our general and limited partners, we received $15.0 million from our noncontrolling interest, received $1.8 million from our general partner, paid $3.2 million in financing costs to amend our Credit Agreement and paid $4.9 million for the purchase of common units for recipients of our incentive grants.

Capital Requirements

Our pipeline and terminalling operations are capital intensive, requiring investments to maintain, expand, upgrade or enhance existing operations and to meet environmental and operational regulations. Our capital requirements have consisted of, and are expected to continue to consist of, maintenance capital expenditures and expansion capital expenditures. “Maintenance capital expenditures” represent capital expenditures to replace partially or fully depreciated assets to maintain the operating capacity of existing assets. Maintenance capital expenditures include expenditures required to maintain equipment reliability, tankage and pipeline integrity, safety and to address environmental regulations. “Expansion capital expenditures” represent capital expenditures to expand the operating capacity of existing or new assets, whether through construction or acquisition. Expansion capital expenditures include expenditures to acquire assets, to grow our business and to expand existing facilities, such as projects that increase throughput capacity on our pipelines and in our terminals. Repair and maintenance expenses associated with existing assets that are minor in nature and do not extend the useful life of existing assets are charged to operating expenses as incurred.

Each year the board of directors of HLS approves our annual capital budget, which specifies capital projects that our management is authorized to undertake. Additionally, at times when conditions warrant or as new opportunities arise, additional projects may be approved. The funds allocated for a particular capital project may be expended over a period in excess of a year, depending on the time required to complete the project. Therefore, our planned capital expenditures for a given year consist of expenditures approved for capital projects included in the current year's capital budget as well as, in certain cases, expenditures approved for capital projects in capital budgets for prior years. The 2015 capital budget is comprised of $9.7 million for maintenance capital expenditures and $77.7 million for expansion capital expenditures. We expect the majority of the expansion capital budget to be invested in crude storage for HFC's El Dorado refinery, product distribution enhancements, new storage tanks, and an additional UNEV origin connection. In addition to our capital budget, we may spend funds periodically to perform capital upgrades or additions to our assets where a customer reimburses us for such costs. The upgrades or additions would generally benefit the customer over the remaining life of the related service agreements.

We substantially completed the expansion of our crude oil transportation system in southeastern New Mexico in the third quarter of 2014 in response to increased crude oil production in the area. The expansion provides shippers with additional pipeline takeaway capacity to either common carrier pipeline stations for transportation to major crude oil markets or to HFC's New Mexico refining facilities. To complete the project, we converted an existing refined products pipeline to crude oil service, constructed several new pipeline segments, expanded an existing pipeline, and built new truck unloading stations and crude storage capacity. Excluding the value of the existing pipeline converted, total capital expenditures were approximately $50 million. HFC has contracted to reimburse us for the increase over the original budget range of $35 million to $40 million over a five year period through an additional fee on shipped volumes. We estimate the project will provide increased capacity of up to 100,000 barrels per day across the system.

UNEV completed a project to enhance its product terminal in Las Vegas, Nevada in the third quarter of 2014 with total capital expenditures of approximately $15 million.

We have announced that we are evaluating the potential construction of several new tanks at HFC’s El Dorado Refinery as well as additional pipeline connections that could increase the refinery’s crude flexibility. As this potential project is still under consideration, the HLS board has not yet approved a capital budget for such project. We have received engineering estimates for this potential project. Alternatively, we are evaluating the potential purchase of existing tanks.

We expect that our currently planned maintenance capital expenditures, as well as expenditures for acquisitions and capital development projects, will be funded with cash generated by operations, the sale of additional limited partner common units, the issuance of debt securities and advances under our Credit Agreement, or a combination thereof.

Under the terms of the transaction to acquire HFC's 75% interest in UNEV, we issued to HFC a Class B unit comprising a noncontrolling equity interest in a wholly-owned subsidiary subject to redemption to the extent that HFC is entitled to a 50% interest in our share of annual UNEV earnings before interest, income taxes, depreciation and amortization above $30 million beginning July 1, 2016, and ending in June 2032, subject to certain limitations.

Credit Agreement

Our $650.0 million senior secured revolving credit facility expires in November 2018 (the “Credit Agreement”) and is available to fund capital expenditures, investments, acquisitions, distribution payments and working capital and for general partnership purposes. It is also available to fund letters of credit up to a $50 million sub-limit.

Our obligations under the Credit Agreement are collateralized by substantially all of our assets. Indebtedness under the Credit Agreement is recourse to HEP Logistics, our general partner, and is guaranteed by our material wholly-owned subsidiaries. Any recourse to HEP Logistics would be limited to the extent of its assets, which other than its investment in us, are not significant. We may prepay all loans at any time without penalty, except for payment of certain breakage and related costs.

Indebtedness under the Credit Agreement bears interest, at our option, at either (a) the reference rate as announced by the administrative agent plus an applicable margin (ranging from 0.625% to 1.50%) or (b) at a rate equal to the London Interbank Offered Rate ("LIBOR") plus an applicable margin (ranging from 1.625% to 2.50%). In each case, the applicable margin is based upon the ratio of our funded debt (as defined in the Credit Agreement) to EBITDA (earnings before interest, taxes, depreciation and amortization, as defined in the Credit Agreement). We incur a commitment fee on the unused portion of the Credit Agreement at an annual rate ranging from 0.30% to 0.45% based upon the ratio of our funded debt to EBITDA for the four most recently completed fiscal quarters.

The Credit Agreement imposes certain requirements on us with which we are currently in compliance, including: a prohibition against distribution to unitholders if, before or after the distribution, a potential default or an event of default as defined in the agreement would occur; limitations on our ability to incur debt, make loans, acquire other companies, change the nature of our business, enter into a merger or consolidation, or sell assets; and covenants that require maintenance of a specified EBITDA to interest expense ratio, total debt to EBITDA ratio and senior debt to EBITDA ratio. If an event of default exists under the Credit Agreement, the lenders will be able to accelerate the maturity of the debt and exercise other rights and remedies.

Senior Notes

In March 2014, we redeemed the $150 million aggregate principal amount of our 8.25% Senior Notes maturing March 2018 at a redemption cost of $156.2 million, at which time we recognized a $7.7 million early extinguishment loss consisting of a $6.2 million debt redemption premium and unamortized discount and financing costs of $1.5 million. We funded the redemption with borrowings under our Credit Agreement.

We have $300 million in aggregate principal amount outstanding of 6.5% Senior Notes maturing March 2020. The 6.5% Senior Notes are unsecured and impose certain restrictive covenants with which we are currently in compliance, including limitations on our ability to incur additional indebtedness, make investments, sell assets, incur certain liens, pay distributions, enter into transactions with affiliates, and enter into mergers. At any time when the 6.5% Senior Notes are rated investment grade by both Moody’s and Standard & Poor’s and no default or event of default exists, we will not be subject to many of the foregoing covenants. Additionally, we have certain redemption rights at varying premiums over face value under the 6.5% Senior Notes.

Indebtedness under the 6.5% Senior Notes is recourse to HEP Logistics, our general partner, and is guaranteed by our material, wholly-owned subsidiaries. However, any recourse to HEP Logistics would be limited to the extent of its assets, which other than its investment in us, are not significant.

Our purchase and contribution agreements with HFC with respect to the intermediate pipelines acquired in 2005 and the crude pipelines and tankage assets acquired in 2008, restrict us from selling these pipelines and terminals acquired from HFC. Under these agreements, we are restricted from prepaying borrowings and long-term debt to outstanding balances below $206 million prior to 2015 and $171 million prior to 2018, subject to certain limited exceptions.

Long-term Debt

The carrying amounts of our long-term debt are as follows:

	December 31, 2014	December 31, 2013
	(In thousands)	
Credit Agreement	$571,000	$363,000
6.5% Senior Notes		
Principal	300,000	300,000
Unamortized discount	(3,421)	(4,073)

	296,579	295,927
8.25% Senior Notes		
Principal	—	150,000
Unamortized discount	—	(1,297)
	—	148,703
Total long-term debt	$867,579	$807,630

See “Risk Management” for a discussion of our interest rate swaps.

Long-term Contractual Obligations
The following table presents our long-term contractual obligations as of December 31, 2014.

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	Over 5 Years
	(In thousands)				
Long-term debt – principal	$871,000	$—	$—	$571,000	$300,000
Long-term debt - interest	156,795	31,886	63,773	51,386	9,750
Pipeline operating lease	16,770	6,708	10,062	—	—
Right-of-way leases	1,202	220	400	316	266
Other	13,823	1,785	3,388	2,356	6,294
Total	$1,059,590	$40,599	$77,623	$625,058	$316,310

Long-term debt consists of outstanding principal under the Credit Agreement and 6.5% Senior Notes. Interest on the credit agreement is calculated using the rate in effect at December 31, 2014.
The pipeline operating lease amounts above reflect the exercise of the 10-year extension, expiring in 2017, on our lease agreement for the refined products pipeline between White Lakes Junction and Kuntz Station in New Mexico.
Most of our right-of-way agreements are renewable on an annual basis, and the right-of-way lease payments above include only obligations under the remaining non-cancelable terms of these agreements at December 31, 2014. For the foreseeable future, we intend to continue renewing these agreements and expect to incur right-of-way expenses in addition to the payments listed.
Other contractual obligations consist of site service agreements with HFC, expiring in 2024 through 2026, for the provision of certain facility services and utility costs that relate to our assets located at HFC's refinery facilities.

Impact of Inflation
Inflation in the United States has been relatively moderate in recent years and did not have a material impact on our results of operations for the years ended December 31, 2014, 2013 and 2012. Historically, the PPI has increased an average of 2.2% annually over the past five calendar years.

The substantial majority of our revenues are generated under long-term contracts that provide for increases in our rates and minimum revenue guarantees annually for increases in the PPI. Certain of these contracts have provisions that limit the level of annual PPI percentage rate increases. Although the recent PPI increase may not be indicative of additional increases to be realized in the future, a significant and prolonged period of high inflation could adversely affect our cash flows and results of operations if costs increase at a rate greater than the fees we charge our shippers.

Environmental Matters
Our operation of pipelines, terminals, and associated facilities in connection with the storage and transportation of refined products is subject to stringent and complex federal, state, and local laws and regulations governing the discharge of materials into the environment, or otherwise relating to the protection of the environment. As with the industry generally, compliance with existing and anticipated laws and regulations increases our overall cost of business, including our capital costs to construct, maintain, and upgrade equipment and facilities. Although these laws and regulations affect our maintenance capital expenditures and net income, we do not believe they affect our competitive position as the operations of our competitors are similarly affected. We believe that our operations are in substantial compliance with applicable environmental laws and regulations. However, these laws and regulations, and the interpretation or enforcement thereof, are subject to frequent change by regulatory authorities, and we are unable to predict the ongoing cost to us of complying with these laws and regulations or the future impact of these laws and regulations on our operations. Violation of environmental laws, regulations, and permits can result in the imposition of significant administrative, civil and criminal penalties, injunctions, and construction bans or delays. A discharge of hydrocarbons or hazardous substances into the environment could, to the extent the event is not insured, subject us to

substantial expense, including both the cost to comply with applicable laws and regulations and claims made by employees, neighboring landowners and other third parties for personal injury and property damage. Contamination resulting from spills of refined products and crude oil is not unusual within the petroleum pipeline industry. Historic spills along our existing pipelines and terminals as a result of past operations have resulted in contamination of the environment, including soils and groundwater. Site conditions, including soils and groundwater, are being evaluated at a few of our properties where operations may have resulted in releases of hydrocarbons and other wastes, none of which we believe will have a significant effect on our operations since the remediation of such releases would be covered under environmental indemnification agreements. For example, we have an environmental agreement with Alon with respect to pre-closing environmental costs and liabilities relating to the pipelines and terminals acquired from Alon in 2005, under which Alon will indemnify us subject to certain monetary and time limitations. In addition, under the Omnibus Agreement and certain transportation agreements and purchase agreements with HFC, HFC has agreed to indemnify us, subject to certain monetary and time limitations, for environmental noncompliance and remediation liabilities associated with certain assets transferred to us from HFC and occurring or existing prior to the date of such transfers. There are environmental remediation projects currently in progress that relate to certain assets acquired from HFC. Certain of these projects were underway prior to our purchase and represent liabilities of HFC for future remediation activities retained by HFC. Additionally, as of December 31, 2014, we have an accrual of $5.2 million that relates to environmental clean-up projects for which we have assumed liability or for which the indemnity provided for by HFC has expired or will expire. The remaining projects, including assessment and monitoring activities, are covered under the HFC environmental indemnification discussed above and represent liabilities of HFC.

CRITICAL ACCOUNTING POLICIES

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities as of the date of the financial statements. Actual results may differ from these estimates under different assumptions or conditions. We consider the following policies to be the most critical to understanding the judgments that are involved and the uncertainties that could impact our results of operations, financial condition and cash flows.

Revenue Recognition

Revenues are recognized as products are shipped through our pipelines and terminals. Additional pipeline transportation revenues result from an operating lease by Alon USA, L.P. of an interest in the capacity of one of our pipelines.

Billings to customers for their obligations under their quarterly minimum revenue commitments are recorded as deferred revenue liabilities if the customer has the right to receive future services for these billings. The revenue is recognized at the earlier of:

- the customer receiving the future services provided by these billings,
- the period in which the customer is contractually allowed to receive the services expires, or
- our determination that we will not be required to provide services within the allowed period.

We determine that we will not be required to provide services within the allowed period when, based on current and projected shipping levels, our pipeline systems will not have the necessary capacity to enable a customer to exceed its minimum volume levels to such a degree as to utilize the shortfall credit within its respective contractual shortfall make-up period.

Goodwill and Long-Lived Assets

Goodwill represents the excess of our cost of an acquired business over the fair value of the assets acquired, less liabilities assumed. Goodwill is not amortized and is tested for impairment annually or more frequently if events or changes in circumstances indicate goodwill may be impaired. We test goodwill at the reporting unit level for impairment annually and between annual tests if events or changes in circumstances indicate the carrying amount may exceed fair value. Recoverability is determined by comparing the estimated fair value of a reporting unit to the carrying value, including the related goodwill, of that reporting unit. We use the present value of the expected future net cash flows and market multiple analyses to determine the estimated fair values of the reporting units. The impairment test requires the use of projections, estimates and assumptions as to the future performance of our operations. Actual results could differ from projections resulting in revisions to our assumptions, and if required, recognizing an impairment loss.

We evaluate long-lived assets, including finite-lived intangible assets, for potential impairment by identifying whether indicators of impairment exist and, if so, assessing whether the long-lived assets are recoverable from estimated future undiscounted cash flows. The actual amount of impairment loss, if any, to be recorded is equal to the amount by which a long-lived asset’s carrying value exceeds its fair value.

There have been no impairments to goodwill or our long-lived assets as of December 31, 2014.

Contingencies
It is common in our industry to be subject to proceedings, lawsuits and other claims related to environmental, labor, product and other matters. We are required to assess the likelihood of any adverse judgments or outcomes to these types of matters as well as potential ranges of probable losses. A determination of the amount of reserves required, if any, for these types of contingencies is made after careful analysis of each individual issue. The required reserves may change in the future due to developments in each matter or changes in approach such as a change in settlement strategy in dealing with these potential matters.

New Accounting Pronouncements

Revenue Recognition
In May 2014, an accounting standard update (ASU 2014-09, "Revenue from Contracts with Customers") was issued requiring revenue to be recognized when promised goods or services are transferred to customers in an amount that reflects the expected consideration for these goods or services. This standard is effective January 1, 2017, and we are evaluating the impact of this standard.

RISK MANAGEMENT

We use interest rate swaps (derivative instruments) to manage our exposure to interest rate risk.

As of December 31, 2014, we have three interest rate swaps, designated as a cash flow hedge, that hedge our exposure to the cash flow risk caused by the effects of LIBOR changes on $305.0 million of Credit Agreement advances. Our first interest rate swap effectively converts $155.0 million of our LIBOR based debt to fixed rate debt having an interest rate of 0.99% plus an applicable margin of 2.00% as of December 31, 2014, which equaled an effective interest rate of 2.99%. This swap contract matures in February 2016. We also have two additional interest rate swaps with identical terms which effectively convert $150.0 million of our LIBOR based debt to fixed rate debt having an interest rate of 0.74% plus an applicable margin of 2.00% as of December 31, 2014, which equaled an effective interest rate of 2.74%. Both of these swap contracts mature in July 2017.

We review publicly available information on our counterparties in order to monitor their financial stability and assess their ongoing ability to honor their commitments under the interest rate swap contracts. These counterparties are large financial institutions. Furthermore, we have not experienced, nor do we expect to experience, any difficulty in the counterparties honoring their respective commitments.

The market risk inherent in our debt positions is the potential change arising from increases or decreases in interest rates as discussed below.

At December 31, 2014, we had an outstanding principal balance on our 6.5% Senior Notes of $300 million. A change in interest rates generally would affect the fair value of the 6.5% Senior Notes, but not our earnings or cash flows. At December 31, 2014, the fair value of our 6.5% Senior Notes was $291.0 million. We estimate a hypothetical 10% change in the yield-to-maturity applicable to the 6.5% Senior Notes at December 31, 2014, would result in a change of approximately $8.5 million in the fair value of the underlying notes.

For the variable rate Credit Agreement, changes in interest rates would affect cash flows, but not the fair value. At December 31, 2014, borrowings outstanding under the Credit Agreement were $571.0 million. By means of our cash flow hedges, we have effectively converted the variable rate on $305.0 million of outstanding borrowings to a fixed rate. For the remaining unhedged Credit Agreement borrowings of $266.0 million, a hypothetical 10% change in interest rates applicable to the Credit Agreement would not materially affect our cash flows.

Our operations are subject to normal hazards of operations, including fire, explosion and weather-related perils. We maintain various insurance coverages, including business interruption insurance, subject to certain deductibles. We are not fully insured against certain risks because such risks are not fully insurable, coverage is unavailable, or premium costs, in our judgment, do not justify such expenditures.

We have a risk management oversight committee that is made up of members from our senior management. This committee monitors our risk environment and provides direction for activities to mitigate, to an acceptable level, identified risks that may adversely affect the achievement of our goals.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. See “Risk Management” under “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for a discussion of market risk exposures that we have with respect to our long-term debt. We utilize derivative instruments to hedge our interest rate exposure, as discussed under “Risk Management.”

Since we do not own products shipped on our pipelines or terminalled at our terminal facilities, we do not have direct market risks associated with commodity prices.

Item 8. Financial Statements and Supplementary Data

MANAGEMENT’S REPORT ON ITS ASSESSMENT OF THE PARTNERSHIP’S INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Holly Energy Partners, L.P. (the “Partnership”) is responsible for establishing and maintaining adequate internal control over financial reporting.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management assessed the Partnership’s internal control over financial reporting as of December 31, 2014, using the criteria for effective control over financial reporting established in “Internal Control – Integrated Framework” issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on this assessment, management concluded that, as of December 31, 2014, the Partnership maintained effective internal control over financial reporting.

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 as of December 31, 2014. That report appears on page 55.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors of Holly Logistic Services, L.L.C. and
Unitholders of Holly Energy Partners, L.P.

We have audited Holly Energy Partners, L.P.'s (the "Partnership") internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Holly Energy Partners, L.P.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on its Assessment of the Partnership's Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, Holly Energy Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Holly Energy Partners, L.P. as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, cash flows, and partners' equity for each of the three years in the period ended December 31, 2014, and our report dated February 25, 2015, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP
Dallas, Texas
February 25, 2015

Index to Consolidated Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors of Holly Logistic Services, L.L.C. and
Unitholders of Holly Energy Partners, L.P.

We have audited the accompanying consolidated balance sheets of Holly Energy Partners, L.P. (the "Partnership") as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, cash flows, and partners' equity for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Holly Energy Partners, L.P. at December 31, 2014 and 2013, and the consolidated results of its operations and its cash flows, for each of the three years in the period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Holly Energy Partners, L.P.'s internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 25, 2015 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP
Dallas, Texas
February 25, 2015

HOLLY ENERGY PARTNERS, L.P.
CONSOLIDATED BALANCE SHEETS
(in thousands, except unit data)

	December 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$2,830	$6,352
Accounts receivable:		
Trade	6,737	5,061
Affiliates	33,392	29,675
	40,129	34,736
Prepaid and other current assets	4,383	3,874
Total current assets	47,342	44,962
Properties and equipment, net	980,479	957,814
Transportation agreements, net	80,703	87,650
Goodwill	256,498	256,498
Investment in SLC Pipeline	24,478	24,741
Other assets	12,055	10,843
Total assets	$1,401,555	$1,382,508
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$12,642	$14,414
Affiliates	5,239	8,484
	17,881	22,898
Accrued interest	6,615	10,239
Deferred revenue	12,432	13,981
Accrued property taxes	2,703	2,603
Other current liabilities	4,571	1,845
Total current liabilities	44,202	51,566
Long-term debt	867,579	807,630
Other long-term liabilities	18,145	14,585
Deferred revenue	29,392	21,669
Class B unit	26,793	20,124
Equity:		
Partners' equity:		
Common unitholders (58,657,048 units issued and outstanding at December 31, 2014 and 2013)	468,813	516,147
General partner interest (2% interest)	(148,405)	(146,557)
Accumulated other comprehensive loss	(46)	(144)
Total partners' equity	320,362	369,446

Noncontrolling interest	95,082	97,488
Total equity	415,444	466,934
Total liabilities and equity	$1,401,555	$1,382,508

See accompanying notes.

HOLLY ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per unit data)

	Years Ended December 31,		
	2014	2013	2012
Revenues:			
Affiliates	$275,196	$252,368	$245,582
Third parties	57,349	52,814	46,978
	332,545	305,182	292,560
Operating costs and expenses:			
Operations (exclusive of depreciation and amortization)	104,801	99,444	89,242
Depreciation and amortization	62,166	65,423	57,461
General and administrative	10,824	11,749	7,594
	177,791	176,616	154,297
Operating income	154,754	128,566	138,263
Other income (expense):			
Equity in earnings of SLC Pipeline	2,987	2,826	3,364
Interest expense	(36,101)	(47,010)	(47,182)
Interest income	3	161	—
Loss on early extinguishment of debt	(7,677)	—	(2,979)
Gain on sale of assets	—	1,810	—
Other income	82	61	10
	(40,706)	(42,152)	(46,787)
Income before income taxes	114,048	86,414	91,476
State income tax expense	(235)	(333)	(371)
Net income	113,813	86,081	91,105
Allocation of net loss attributable to Predecessors	—	—	4,200
Allocation of net income attributable to noncontrolling interests	(8,288)	(6,632)	(1,153)
Net income attributable to Holly Energy Partners	105,525	79,449	94,152
General partner interest in net income, including incentive distributions	(34,667)	(27,523)	(22,450)
Limited partners’ interest in net income	$70,858	$51,926	$71,702
Limited partners’ per unit interest in earnings—basic and diluted	$1.20	$0.88	$1.29
Weighted average limited partners’ units outstanding	58,657	58,246	55,696

See accompanying notes.

HOLLY ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In thousands)

	Years Ended December 31,		
	2014	2013	2012
Net income	$113,813	$86,081	$91,105
Other comprehensive income:			
Change in fair value of cash flow hedging instruments	(2,104)	1,194	(4,418)
Amortization of unrealized loss attributable to discontinued cash flow hedge	—	849	5,095
Reclassification adjustment to net income on partial settlement of cash flow hedge	2,202	2,092	1,508
Other comprehensive income	98	4,135	2,185
Comprehensive income before noncontrolling interest	113,911	90,216	93,290
Allocation of comprehensive income to noncontrolling interests	(8,288)	(6,632)	(1,153)
Allocation of net loss attributable to Predecessors	—	—	4,200
Comprehensive income attributable to Holly Energy Partners	$105,623	$83,584	$96,337

See accompanying notes.

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

	Years Ended December 31,		
	2014	2013	2012
Cash flows from operating activities			
Net income	$113,813	$86,081	$91,105
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	62,166	65,423	57,461
Gain on sale of assets	—	(1,810)	—
Amortization of deferred charges	1,820	2,970	7,556
Amortization of restricted and performance units	3,539	3,575	2,858
Loss on early extinguishment of debt	7,677	—	2,979
(Increase) decrease in operating assets:			
Accounts receivable—trade	(1,676)	2,065	(3,997)
Accounts receivable—affiliates	(3,717)	1,919	(135)
Prepaid and other current assets	(510)	(255)	110
Increase (decrease) in operating liabilities:			
Accounts payable—trade	2,469	3,365	(9,003)
Accounts payable—affiliates	(3,245)	3,821	(1,811)
Accrued interest	(3,624)	13	1,945
Deferred revenue	6,173	15,255	11,333
Accrued property taxes	100	(85)	492
Other current liabilities	1,819	(45)	113
Other, net	(164)	788	143
Net cash provided by operating activities	186,640	183,080	161,149
Cash flows from investing activities			
Additions to properties and equipment	(79,959)	(52,101)	(42,861)
Proceeds from sale of assets	—	2,731	—
Distributions in excess of equity in earnings in SLC pipeline	263	300	262
Net cash used for investing activities	(79,696)	(49,070)	(42,599)
Cash flows from financing activities			
Borrowings under credit agreement	642,300	310,600	587,000
Repayments of credit agreement borrowings	(434,300)	(368,600)	(366,000)
Proceeds from issuance of senior notes	—	—	294,750
Proceeds from issuance of common units	—	73,444	—
Cash distribution to HFC for UNEV acquisition	—	—	(260,922)
Redemption of senior notes	(156,188)	—	(260,235)
Contributions from noncontrolling interests	—	—	15,000
Contributions from general partner	—	1,499	1,748
Distributions to HEP unitholders	(154,670)	(139,486)	(122,777)
Distributions to noncontrolling interest	(4,025)	(3,125)	—
Purchase of units for incentive grants	(3,577)	(5,634)	(4,919)
Deferred financing costs	—	(1,344)	(3,238)
Other	(6)	(249)	(89)
Net cash used by financing activities	(110,466)	(132,895)	(119,682)

Cash and cash equivalents			
Increase (decrease) for the year	(3,522)	1,115	(1,132)
Beginning of year	6,352	5,237	6,369
End of year	$2,830	$6,352	$5,237

See accompanying notes.

HOLLY ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY
(In thousands)

	Holly Energy Partners, L.P. Partners' Equity (Deficit):				
	Common Units	General Partner Interest	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Total
Balance December 31, 2011	481,439	163,701	(6,464)	99,002	737,678
Capital contribution	—	10,286	—	3,000	13,286
Distributions to HEP unitholders	(99,744)	(23,033)	—	—	(122,777)
Purchase of 75% interest in UNEV from HFC:					
Cash distribution	—	(260,922)	—	—	(260,922)
Issuance of common units	45,839	(45,839)	—	—	—
Issuance of Class B unit	—	(12,200)	—	—	(12,200)
Purchase of units for incentive grants	(4,713)	—	—	—	(4,713)
Amortization of restricted and performance units	2,858	—	—	—	2,858
Class B unit accretion	(1,694)	(9)	—	—	(1,703)
Tankage and terminal assets acquired from HFC:					
Transferred basis in properties	7,947	—	—	—	7,947
Other	—	112	—	—	112
Net income	70,877	22,027	—	(1,799)	91,105
Other comprehensive income	—	—	2,185	—	2,185
Balance December 31, 2012	502,809	(145,877)	(4,279)	100,203	452,856
Issuance of common units	73,444	—	—	—	73,444
Capital contribution	—	1,499	—	—	1,499
Distributions to HEP unitholders	(112,039)	(27,447)	—	—	(139,486)
Distributions to noncontrolling interests	—	—	—	(3,125)	(3,125)
Purchase of units for incentive grants	(5,313)	—	—	—	(5,313)
Amortization of restricted and performance units	3,575	—	—	—	3,575
Class B unit accretion	(6,097)	(124)	—	—	(6,221)
Other	(248)	(263)	—	—	(511)
Net income	60,016	25,655	—	410	86,081
Other comprehensive income	—	—	4,135	—	4,135
Balance December 31, 2013	$516,147	$(146,557)	$ (144)	$ 97,488	$466,934
Distributions to HEP unitholders	(119,944)	(34,726)	—	—	(154,670)
Distributions to noncontrolling interests	—	—	—	(4,025)	(4,025)
Purchase of units for incentive grants	(3,577)	—	—	—	(3,577)
Amortization of restricted and performance units	3,539	—	—	—	3,539
Class B unit accretion	(6,534)	(134)	—	—	(6,668)
Net income	79,182	33,012	—	1,619	113,813
Other comprehensive income	—	—	98	—	98
Balance December 31, 2014	$468,813	$(148,405)	$ (46)	$ 95,082	$415,444

See accompanying notes.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2014

Note 1: Description of Business and Summary of Significant Accounting Policies

Holly Energy Partners, L.P. (“HEP”) together with its consolidated subsidiaries, is a publicly held master limited partnership which is 39% owned (including the 2% general partner interest) by HollyFrontier Corporation (“HFC”) and its subsidiaries. We commenced operations on July 13, 2004, upon the completion of our initial public offering. In these consolidated financial statements, the words “we,” “our,” “ours” and “us” refer to HEP unless the context otherwise indicates.

We operate in one reportable segment which represents the aggregation of our petroleum product and crude pipelines business and terminals, tankage and loading rack facilities operations.

We own and operate petroleum product and crude oil pipelines and terminal, tankage and loading rack facilities that support HFC’s refining and marketing operations in the Mid-Continent, Southwest and Rocky Mountain regions of the United States and Alon USA, Inc.’s (“Alon”) refinery in Big Spring, Texas. Additionally, we own a 75% interest in the UNEV Pipeline, LLC (“UNEV”), which owns a 427-mile, 12-inch refined products pipeline running from Woods Cross, Utah to Las Vegas, Nevada (the “UNEV Pipeline”), product terminals near Cedar City, Utah and Las Vegas, Nevada and related assets, and a 25% interest in SLC Pipeline LLC, which owns a 95-mile intrastate crude oil pipeline system (the “SLC Pipeline”) that serves refineries in the Salt Lake City, Utah area.

We generate revenues by charging tariffs for transporting petroleum products and crude oil through our pipelines, by charging fees for terminalling and storing refined products and other hydrocarbons and providing other services at our storage tanks and terminals. We do not take ownership of products that we transport, terminal or store, and therefore, we are not exposed directly to changes in commodity prices.

Principles of Consolidation and Common Control Transactions
The consolidated financial statements include our accounts and those of subsidiaries and joint ventures that we control through a 50% or more ownership interest. All significant inter-company transactions and balances have been eliminated.

Most of our asset acquisitions from HFC occurred while we were a consolidated variable interest entity of HFC. Therefore, as an entity under common control with HFC, we recorded these assets on our balance sheets at HFC's historical basis instead of our purchase price or fair value.

Use of Estimates
The preparation of financial statements in accordance with U.S. generally accepted accounting principles (“GAAP”) requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Cash and Cash Equivalents
For purposes of the statements of cash flows, we consider all highly liquid investments with maturities of three months or less at the time of purchase to be cash equivalents. The carrying amounts reported on the balance sheets approximate fair value due to the short-term maturity of these instruments.

Accounts Receivable
The majority of the accounts receivable are due from affiliates of HFC, Alon or independent companies in the petroleum industry. Credit is extended based on evaluation of the customer's financial condition and, in certain

circumstances, collateral such as letters of credit or guarantees, may be required. Credit losses are charged to income when accounts are deemed uncollectible and historically have been minimal.

Properties and Equipment

Properties and equipment are stated at cost. Properties and equipment acquired from HFC while under common control of HFC are stated at HFC's historical basis. Depreciation is provided by the straight-line method over the estimated useful lives of the assets, primarily 15 to 25 years for terminal facilities and tankage, 25 to 32 years for pipelines and 5 to 10 years for corporate and other assets. We depreciate assets acquired under capital leases over the lesser of the lease term or the economic life of the assets. Maintenance, repairs and minor replacements are expensed as incurred. Costs of replacements constituting improvements are capitalized.

Transportation Agreements
The transportation agreement assets are stated at acquisition date fair value and are being amortized over the periods of the agreements using the straight-line method. See Note 5 for additional information on our transportation agreements.

Goodwill and Long-Lived Assets
Goodwill represents the excess of our cost of an acquired business over the fair value of the assets acquired, less liabilities assumed. Goodwill is not amortized and is tested for impairment annually or more frequently if events or changes in circumstances indicate goodwill may be impaired. We test goodwill at the reporting unit level for impairment annually and between annual tests if events or changes in circumstances indicate the carrying amount may exceed fair value. Recoverability is determined by comparing the estimated fair value of a reporting unit to the carrying value, including the related goodwill, of that reporting unit. We use the present value of the expected future net cash flows and market multiple analyses to determine the estimated fair values of the reporting units. The impairment test requires the use of projections, estimates and assumptions as to the future performance of our operations. Actual results could differ from projections resulting in revisions to our assumptions, and if required, recognizing an impairment loss.

We evaluate long-lived assets, including finite intangible assets, for potential impairment by identifying whether indicators of impairment exist and, if so, assessing whether the long-lived assets are recoverable from estimated future undiscounted cash flows. The actual amount of impairment loss, if any, to be recorded is equal to the amount by which a long-lived asset's carrying value exceeds its fair value.

There have been no impairments to goodwill or our long-lived assets as of December 31, 2014.

Investment in SLC Pipeline
We account for our 25% SLC Pipeline joint venture interest using the equity method of accounting, whereby we record our pro-rata share of earnings of the SLC Pipeline, and contributions to and distributions from the SLC Pipeline as adjustments to our investment balance. As of December 31, 2014, our underlying equity in the SLC Pipeline was $58.9 million compared to our recorded investment balance of $24.5 million, a difference of $34.4 million. We are amortizing this difference as an adjustment to our pro-rata share of earnings over the useful lives of the underlying assets of SLC Pipeline.

Asset Retirement Obligations
We record legal obligations associated with the retirement of certain of our long-lived assets that result from the acquisition, construction, development and/or the normal operation of our long-lived assets. The fair value of the estimated cost to retire a tangible long-lived asset is recorded in the period in which the liability is incurred and when a reasonable estimate of the fair value of the liability can be made. For our pipeline assets, the right-of-way agreements typically do not require the dismantling, removal and reclamation of the right-of-way upon cessation of the pipeline service. Additionally, management is unable to predict when, or if, our pipelines and related facilities would become obsolete and require decommissioning. Accordingly, we have recorded no liability or corresponding asset related to an asset retirement obligation for the majority of our pipelines as both the amounts and timing of such potential future costs are indeterminable. For our remaining assets, at December 31, 2014 and 2013, we have asset retirement obligations of $6.8 million and $6.5 million, respectively, that are recorded under “Other long-term liabilities” in our consolidated balance sheets.

Revenue Recognition
Revenues are recognized as products are shipped through our pipelines and terminals or other services are rendered. Billings to customers for their obligations under their quarterly minimum revenue commitments are recorded as deferred revenue liabilities if the customer has the right to receive future services for these billings. The revenue is recognized at the earlier of:

- the customer receiving the future services provided by these billings,
- the period in which the customer is contractually allowed to receive the services expires, or
- our determination that we will not be required to provide services within the allowed period.

We determine that we will not be required to provide services within the allowed period when, based on current and projected shipping levels, our pipeline systems will not have the necessary capacity to enable a customer to exceed its minimum volume levels to such a degree as to utilize the shortfall credit within its respective contractual shortfall make-up period.

We have additional revenues under an operating lease to a third party of an interest in the capacity of one of our pipelines.

As of December 31, 2014, billings to customers under their minimum revenue commitments per the terms of long-term throughput agreements expiring in 2019 through 2026 and the third party operating lease will result in minimum annualized payments to us in the aggregate of $2.5 billion including $272.4 million for each of the next five years. These agreements provide for increases in the minimum revenue guarantees annually for increases in the Producer Price Index ("PPI") or the Federal Energy Regulatory Commission ("FERC") index, with certain contracts having provisions that limit the level of the rate increases.

We have other cost reimbursement provisions in our throughput / storage agreements providing that customers (including HFC) reimburse us for certain costs. Such reimbursement receipts are recorded as revenue or deferred revenue depending on the nature of the cost. Deferred revenue is recognized over the remaining contractual term of the related throughput agreement.

Taxes billed and collected from our pipeline and terminal customers are recorded on a net basis with no effect on net income.

Environmental Costs

Environmental costs are expensed if they relate to an existing condition caused by past operations and do not contribute to current or future revenue generation. Liabilities are recorded when site restoration and environmental remediation, cleanup and other obligations are either known or considered probable and can be reasonably estimated. Such estimates require judgment with respect to costs, time frame and extent of required remedial and clean-up activities and are subject to periodic adjustments based on currently available information. At December 31, 2014 and 2013, we had accrued liabilities, measured on an undiscounted basis, net of expected recoveries from indemnifying parties, for environmental remediation obligations of $5.2 million and $3.6 million respectively, of which $2.3 million and $0.4 million, respectively, were classified as other current liabilities.

Under the Omnibus Agreement and certain transportation agreements and purchase agreements with HFC, HFC has agreed to indemnify us, subject to certain monetary and time limitations, for environmental noncompliance and remediation liabilities associated with certain assets transferred to us from HFC occurring or existing prior to the date of such transfers. We have an environmental agreement with Alon with respect to pre-closing environmental costs and liabilities relating to the pipelines and terminals acquired from Alon in 2005, under which Alon will indemnify us subject to certain monetary and time limitations. Environmental costs recoverable through insurance, indemnification agreements or other sources are included in other assets to the extent such recoveries are considered probable.

Income Tax

We are subject to the Texas margin tax that is based on our Texas sourced taxable margin. The tax is calculated by applying a tax rate to a base that considers both revenues and expenses and therefore has the characteristics of an income tax.

We are organized as a pass-through entity for federal income tax purposes. As a result, our partners are responsible for federal income taxes based on their respective share of taxable income.

Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the partnership agreement.

Net Income per Limited Partners' Unit

We use the two-class method when calculating the net income per unit applicable to limited partners, which is based on the weighted-average number of common and subordinated units outstanding during the year. Net income per unit applicable to limited partners is computed by dividing limited partners' interest in net income, after adjusting for the allocation of net income or loss attributable to previous owners ("Predecessor"), the allocation of net income or loss attributable to noncontrolling interests and the general partner's 2% interest and incentive distributions and other participating securities, by the weighted-average number of outstanding common, subordinated units and other dilutive securities. Other participating securities and dilutive securities are not significant.

New Accounting Pronouncements

Revenue Recognition

In May 2014, an accounting standard update was issued requiring revenue to be recognized when promised goods or services are transferred to customers in an amount that reflects the expected consideration for these goods or services. This standard is effective January 1, 2017, and we are evaluating the impact of this standard.

Note 2: Acquisitions

2012 UNEV Acquisition
On July 12, 2012, we acquired HFC's 75% interest in UNEV for consideration consisting of $260.0 million in cash and 2,059,800 of our common units. We paid an additional $0.9 million to HFC for a post-closing working capital adjustment. We also issued HFC a Class B unit comprising a noncontrolling equity interest in a wholly-owned subsidiary subject to redemption to the extent that HFC is entitled to a 50% interest in our share of annual UNEV earnings before interest, income taxes, depreciation, and amortization above $30 million beginning July 1, 2016, and ending in June 2032, subject to certain limitations. Such contingent redemption payments are limited to a maximum payment amount calculated as described below. However, to the extent earnings thresholds are not achieved, no redemption payments are required. Contemporaneously with this transaction, HFC (our general partner) agreed to forego its right to incentive distributions of up to $1.25 million per quarter over twelve consecutive quarterly periods and up to an additional four quarters in certain circumstances. The Class B unit increases with each foregone incentive distribution and by a 7% factor compounded annually on the outstanding unredeemed balance through its expiration date. At our option, we may redeem, in whole or in part, the Class B unit at the current unredeemed value based on the calculation described. The Class B unit had a carrying value of $26.8 million at December 31, 2014, and $20.1 million at December 31, 2013.

Noncontrolling interests reported in the Consolidated Statements of Income include the minority partner's 25% interest in UNEV, foregone incentive distributions and the 7% accretion factor, which collectively amounted to $8.3 million at December 31, 2014, $6.6 million at December 31, 2013, and $1.2 million at December 31, 2012.

We are a consolidated variable interest entity of HFC. Therefore, this transaction was recorded as a transfer between entities under common control and reflects HFC's carrying basis in UNEV's assets and liabilities. We have retrospectively adjusted our financial position and operating results as if UNEV were a consolidated subsidiary for all periods while we were under common control of HFC. Results of operations of UNEV prior to our acquisition on July 12, 2012, are herein referred to as operations attributable to the Predecessor. For the year ended December 31, 2012, our consolidated statement of income includes revenues from UNEV of $18.7 million and net losses of $7.2 million. Predecessor revenues for the year ended December 31, 2012, are $8.1 million and Predecessor net losses are $4.2 million. At December 31, 2014, UNEV had transportation agreements with shippers that provide minimum annualized revenues of $27.1 million, of which $18.4 million relates to a transportation agreement with HFC.

Note 3: Financial Instruments

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, debt and interest rate swaps. The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the short-term maturity of these instruments. Debt consists of outstanding principal under our revolving credit agreement (which approximates fair value as interest rates are reset frequently at current interest rates) and our fixed interest rate senior notes.

Fair value measurements are derived using inputs (assumptions that market participants would use in pricing an asset or liability) including assumptions about risk. GAAP categorizes inputs used in fair value measurements into three broad levels as follows:

- (Level 1) Quoted prices in active markets for identical assets or liabilities.
- (Level 2) Observable inputs other than quoted prices included in Level 1, such as quoted prices for similar assets and liabilities in active markets, similar assets and liabilities in markets that are not active or can be corroborated by observable market data.
-

(Level 3) Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities. This includes valuation techniques that involve significant unobservable inputs.

The carrying amounts and estimated fair values of our senior notes and interest rate swaps were as follows:

Financial Instrument	Fair Value Input Level	December 31, 2014 Carrying Value (In thousands)	December 31, 2014 Fair Value	December 31, 2013 Carrying Value	December 31, 2013 Fair Value
Assets:					
Interest rate swaps	Level 2	$1,019	$1,019	$1,670	$1,670
Liabilities:					
Senior notes:					
6.5% Senior Notes	Level 2	$296,579	$291,000	$295,927	$313,500
8.25% Senior Notes	Level 2	—	—	148,703	158,250
		296,579	291,000	444,630	471,750
Interest rate swaps	Level 2	1,065	1,065	1,814	1,814
		$297,644	$292,065	$446,444	$473,564

Level 2 Financial Instruments
Our senior notes and interest rate swaps are measured at fair value using Level 2 inputs. The fair value of the senior notes is based on market values provided by a third-party bank, which were derived using market quotes for similar type debt instruments. The fair value of our interest rate swaps is based on the net present value of expected future cash flows related to both variable and fixed rate legs of the swap agreement. This measurement is computed using the forward London Interbank Offered Rate ("LIBOR") yield curve, a market-based observable input.

See Note 7 for additional information on these instruments.

Note 4: Properties and Equipment

The carrying amounts of our properties and equipment are as follows:

	December 31, 2014 (In thousands)	December 31, 2013
Pipelines, terminals and tankage	$1,137,157	$1,077,037
Land and right of way	64,458	63,425
Construction in progress	56,228	50,454
Other	22,636	19,997
	1,280,479	1,210,913
Less accumulated depreciation	300,000	253,099
	$980,479	$957,814

We capitalized $1.5 million and $0.6 million in interest related to construction projects during the years ended December 31, 2014 and 2013, respectively.

Depreciation expense was $54.7 million, $58.1 million, and $50.1 million for the years ended December 31, 2014, 2013 and 2012, respectively, and includes depreciation of assets acquired under capital leases. Asset abandonment charges of $1.9 million, $6.2 million and $4.8 million for assets permanently removed from service were included in depreciation expense for the years ended December 31, 2014, 2013 and 2012, respectively.

Note 5: Transportation Agreements

Our transportation agreements represent a portion of the total purchase price of certain assets acquired from Alon in 2005 and from HFC in 2008. The Alon agreement is being amortized over 30 years ending 2035 (the initial 15-year term of the agreement plus an expected 15-year extension period) and the HFC agreement is being amortized over 15 years ending 2023 (the term of the HFC agreement).

The carrying amounts of our transportation agreements are as follows:

	December 31, 2014	December 31, 2013
	(In thousands)	
Alon transportation agreement	$59,933	$59,933
HFC transportation agreement	74,231	74,231
	134,164	134,164
Less accumulated amortization	53,461	46,514
	$80,703	$87,650

Amortization expense was $6.9 million for each of the years ended December 31, 2014, 2013 and 2012, respectively.

We have additional transportation agreements with HFC resulting from historical transactions consisting of pipeline, terminal and tankage assets contributed to us or acquired from HFC. These transactions occurred while we were a consolidated variable interest entity of HFC; therefore, our basis in these agreements is zero and does not reflect a step-up in basis to fair value.

Note 6: Employees, Retirement and Incentive Plans

Direct support for our operations is provided by Holly Logistic Services, L.L.C., an HFC subsidiary, which utilizes personnel employed by HFC who are dedicated to performing services for us. Their costs, including salaries, bonuses, payroll taxes, benefits and other direct costs, are charged to us monthly in accordance with an omnibus agreement that we have with HFC. These employees participate in the retirement and benefit plans of HFC. Our share of retirement and benefit plan costs was $7.4 million, $7.4 million and $6.9 million for the years ended December 31, 2014, 2013 and 2012, respectively. These costs include retirement costs of $4.4 million, $5.0 million and $4.3 million for the years ended December 31, 2014, 2013 and 2012, respectively.

We have an incentive plan (“Long-Term Incentive Plan”) for employees and non-employee directors who perform services for us. The Long-Term Incentive Plan consists of four components: restricted or phantom units, performance units, unit options and unit appreciation rights. Our accounting policy for the recognition of compensation expense for awards with pro-rata vesting (a significant proportion of our awards) is to expense the costs ratably over the vesting periods.

As of December 31, 2014, we have three types of incentive-based awards which are described below. The compensation cost charged against income was $3.5 million, $3.6 million and $2.9 million for the years ended December 31, 2014, 2013 and 2012, respectively. We currently purchase units in the open market instead of issuing new units for settlement of all unit awards under our Long-Term Incentive Plan. As of December 31, 2014, 2,500,000 units were authorized to be granted under our Long-Term Incentive Plan, of which 1,530,748 have not yet been granted, assuming no forfeitures of the unvested units and full achievement of goals for the performance units already granted.

Restricted and Phantom Units

Under our Long-Term Incentive Plan, we grant restricted units to non-employee directors and selected employees who perform services for us, with most awards vesting over a period of one to three years. Although full ownership of the units does not transfer to the recipients until the units vest, the recipients have distribution and voting rights on these units from the date of grant.

In addition, we grant phantom units to certain employees, which vest over a period of one year. Vested units are paid in common units. Full ownership of the units does not transfer to the recipient until the units vest, and the recipients do not have voting or distribution rights on these units until they vest.

The fair value of each restricted unit and phantom unit award is measured at the market price as of the date of grant and is amortized over the vesting period.

A summary of restricted unit and phantom unit activity and changes during the year ended December 31, 2014, is presented below:

Restricted and Phantom Units	Units	Weighted-Average Grant-Date Fair Value
Outstanding at January 1, 2014 (nonvested)	122,951	$33.36
Granted	91,852	33.49
Vesting and transfer of full ownership to recipients	(80,645)	33.22
Forfeited	(8,081)	35.28
Outstanding at December 31, 2014 (nonvested)	126,077	$33.43

The fair values of restricted and phantom units that were vested and transferred to recipients during the years ended December 31, 2014, 2013 and 2012 were $2.7 million, $1.2 million and $2.4 million respectively. As of December 31, 2014, there was $3.0 million of total unrecognized compensation expense related to nonvested restricted unit and phantom unit grants, which is expected to be recognized over a weighted-average period of 1.5 years. For the years ended December 31, 2013 and 2012, the grant date closing unit price applied to the number of restricted units and phantom units ultimately awarded was $34.66 and $31.01 respectively.

Performance Units

Under our Long-Term Incentive Plan, we grant performance units to selected executives who perform services for us. Performance units granted are payable based upon the growth in our distributable cash flow per common unit over the performance period, and vest over a period of three years.

We granted 13,967 target performance units to certain officers in October 2014. These units will vest over a three year period ending December 31, 2017. The performance units granted are payable in HEP common units. The number of units actually earned will be based on the growth of our distributable cash flow per common unit over the performance period, and can range from 50% to 150% of the target number of performance units granted. Although common units are not transferred to the recipients until the performance units vest, the recipients have distribution rights with respect to the common units from the date of grant. The fair value of these performance units is based on the grant date closing unit price of $33.57 for the performance units granted in October 2014 and will apply to the number of units ultimately awarded. For the years ended December 31, 2013 and 2012, the weighted average grant date closing unit price applied to the number of units awarded was $37.90 and $30.61 respectively.

A summary of performance unit activity and changes during the twelve months ended December 31, 2014, is presented below:

Performance Units	Units
Outstanding at January 1, 2014 (nonvested)	75,216
Granted	13,967
Vesting and transfer of common units to recipients	(17,938)
Outstanding at December 31, 2014 (nonvested)	71,245

The grant date fair value of performance units vested and transferred to recipients was $0.5 million during each of the three years ended December 31, 2014, 2013 and 2012. Based on the weighted average fair value of performance units outstanding at December 31, 2014, of $2.6 million, there was $1.1 million of total unrecognized compensation expense related to nonvested performance units, which is expected to be recognized over a weighted-average period of 1.2 years.

During the year ended December 31, 2014, we paid $3.6 million for the purchase of our common units in the open market for the issuance and settlement of all unit awards under our Long-Term Incentive Plan.

Note 7: Debt

Credit Agreement
We have a $650 million senior secured revolving credit facility expiring in November 2018 (the “Credit Agreement”) that is available to fund capital expenditures, investments, acquisitions, distribution payments and working capital and for general partnership purposes. It is also available to fund letters of credit up to a $50 million sub-limit.

Our obligations under the Credit Agreement are collateralized by substantially all of our assets. Indebtedness under the Credit Agreement is recourse to HEP Logistics Holdings, L.P. (“HEP Logistics”), our general partner, and is guaranteed by our material wholly-owned subsidiaries. Any recourse to HEP Logistics would be limited to the extent of its assets, which other than its investment in us, are not significant. We may prepay all loans at any time without penalty, except for payment of certain breakage and related costs.

Indebtedness under the Credit Agreement bears interest, at our option, at either (a) the reference rate as announced by the administrative agent plus an applicable margin (ranging from 0.625% to 1.50%) or (b) at a rate equal to LIBOR plus an applicable margin (ranging from 1.625% to 2.50%). In each case, the applicable margin is based upon the ratio of our funded debt (as defined in the Credit Agreement) to EBITDA (earnings before interest, taxes, depreciation and amortization, as defined in the Credit Agreement). The weighted-average interest rates on our Credit Agreement borrowings in effect at December 31, 2014 and 2013, were 2.152% and 2.163%, respectively. We incur a commitment fee on the unused portion of the Credit Agreement at an annual rate ranging from 0.30% to 0.45% based upon the ratio of our funded debt to EBITDA for the four most recently completed fiscal quarters.

The Credit Agreement imposes certain requirements on us with which we are currently in compliance, including: a prohibition against distribution to unitholders if, before or after the distribution, a potential default or an event of default as defined in the agreement would occur; limitations on our ability to incur debt, make loans, acquire other companies, change the nature of our business, enter into a merger or consolidation, or sell assets; and covenants that require maintenance of a specified EBITDA to interest expense ratio, total debt to EBITDA ratio and senior debt to EBITDA ratio. If an event of default exists under the Credit Agreement, the lenders will be able to accelerate the maturity of the debt and exercise other rights and remedies.

Senior Notes
In March 2012, we issued $300 million in aggregate principal amount outstanding of 6.5% Senior Notes maturing March 2020. Net proceeds of $294.8 million were used in March and April 2012 to redeem $185.0 million aggregate principal amount of our 6.25% Senior Notes maturing March 1, 2015, tendered pursuant to a cash tender offer and consent solicitation, to repay $72.9 million in promissory notes related to our November 2011 acquisition of assets located at HFC's El Dorado and Cheyenne refineries, to pay related fees, expenses and accrued interest in connection with these transactions and to repay borrowings under the Credit Agreement. We recognized a charge of $3.0 million upon the early extinguishment of our 6.25% Senior Notes for the year ended December 31, 2012. This charge represents the premium paid to our 6.25% Senior Note holders upon their tender of an aggregate principal amount of $185.0 million and related net discount.

In March 2014, we redeemed the $150 million aggregate principal amount of 8.25% Senior Notes maturing March 2018 at a redemption cost of $156.2 million, at which time we recognized a $7.7 million early extinguishment loss consisting of a $6.2 million debt redemption premium and unamortized discount and financing costs of $1.5 million. We funded the redemption with borrowings under our Credit Agreement.

The 6.5% Senior Notes are unsecured and impose certain restrictive covenants, with which we are currently in compliance, including limitations on our ability to incur additional indebtedness, make investments, sell assets, incur certain liens, pay distributions, enter into transactions with affiliates, and enter into mergers. At any time when the 6.5% Senior Notes are rated investment grade by both Moody’s and Standard & Poor’s and no default or event of default exists, we will not be subject to many of the foregoing covenants. Additionally, we have certain redemption rights at varying premiums over face value under the 6.5% Senior Notes.

Indebtedness under the 6.5% Senior Notes is recourse to HEP Logistics, our general partner, and is guaranteed by our material, wholly-owned subsidiaries. However, any recourse to HEP Logistics would be limited to the extent of its assets, which other than its investment in us, are not significant.

Our purchase and contribution agreements with HFC with respect to the intermediate pipelines acquired in 2005 and the crude pipelines and tankage assets acquired in 2008, restrict us from selling these pipelines and terminals acquired from HFC. Under these agreements, we are restricted from prepaying borrowings and long-term debt to outstanding balances below $206 million prior to 2015 and $171 million prior to 2018, subject to certain limited exceptions.

Long-term Debt

The carrying amounts of our long-term debt are as follows:

	December 31, 2014	December 31, 2013
	(In thousands)	
Credit Agreement	$571,000	$363,000
6.5% Senior Notes		
Principal	300,000	300,000
Unamortized discount	(3,421)	(4,073)
	296,579	295,927
8.25% Senior Notes		
Principal	—	150,000
Unamortized discount	—	(1,297)
	—	148,703
Total long-term debt	$867,579	$807,630

Maturities of our long-term debt are as follows:

Years Ending December 31,	(In thousands)
2015	$—
2016	—
2017	—
2018	571,000
2019	—
Thereafter	300,000
Total	$871,000

Interest Rate Risk Management

We use interest rate swaps (derivative instruments) to manage our exposure to interest rate risk.

As of December 31, 2014, we have three interest rate swaps that hedge our exposure to the cash flow risk caused by the effects of LIBOR changes on $305 million of Credit Agreement advances. Our first interest rate swap effectively converts $155 million of our LIBOR based debt to fixed rate debt having an interest rate of 0.99% plus an applicable margin of 2.00% as of December 31, 2014, which equaled an effective interest rate of 2.99%. This swap contract matures in February 2016. We also have two additional interest rate swaps with identical terms which effectively convert $150 million of our LIBOR based debt to fixed rate debt having an interest rate of 0.74% plus an applicable margin of 2.00% as of December 31, 2014, which equaled an effective interest rate of 2.74%. Both of these swap contracts mature in July 2017.

We have designated these interest rate swaps as cash flow hedges. Based on our assessment of effectiveness using the change in variable cash flows method, we have determined that these interest rate swaps are effective in offsetting the variability in interest payments on $305 million of our variable rate debt resulting from changes in LIBOR. Under hedge accounting, we adjust our cash flow hedges on a quarterly basis to their fair values with the offsetting fair value adjustments to accumulated other comprehensive income (loss). Also on a quarterly basis, we measure hedge effectiveness by comparing the present value of the cumulative change in the expected future interest to be paid or received on the variable leg of our swaps against the expected future interest payments on $305 million of our variable rate debt. Any ineffectiveness is recorded directly to interest expense. As of December 31, 2014, we had no ineffectiveness on our cash flow hedges.

Prior to entering into our first swap contract (discussed above), we terminated our previous interest rate swap that prior to settlement also served to hedge our exposure to the effects of LIBOR changes on the same $155 million Credit Agreement advance. We terminated this swap at a cost of $6 million, to lock in a lower effective interest rate on this $155 million advance, which by means of the previous swap contract was effectively fixed at 6.24% at the time of termination. This cost of terminating the swap was amortized as a charge to interest expense through February 2013, the remaining term of the terminated swap contract.

At December 31, 2014, we have accumulated other comprehensive loss of $46,000 that relates to our current cash flow hedging instruments. Approximately $0.5 million will be transferred from accumulated other comprehensive loss into interest expense as interest is paid on the underlying swap agreement over the next twelve-month period, assuming interest rates remain unchanged.

Additional information on our interest rate swaps is as follows:

Derivative Instrument	Balance Sheet Location	Fair Value	Location of Offsetting Balance	Offsetting Amount
	(In thousands)			
December 31, 2014				
Interest rate swaps designated as cash flow hedging instrument:				
Variable-to-fixed interest rate swap contract ($155 million of LIBOR based debt interest)	Other long-term liabilities	$(1,065)	Accumulated other comprehensive loss	$(1,065)
Variable-to-fixed interest rate swap contract ($150 million of LIBOR based debt interest)	Other long-term assets	1,019	Accumulated other comprehensive income	1,019
		$(46)		$(46)
December 31, 2013				
Interest rate swaps designated as cash flow hedging instrument:				
Variable-to-fixed interest rate swap contract ($155 million of LIBOR based debt interest)	Other long-term liabilities	$(1,814)	Accumulated other comprehensive loss	$(1,814)
Variable-to-fixed interest rate swap contract ($150 million of LIBOR based debt interest)	Other long-term assets	1,670	Accumulated other comprehensive income	1,670
		$(144)		$(144)

Interest Expense and Other Debt Information

Interest expense consists of the following components:

	Years Ended December 31,		
	2014	2013	2012
	(In thousands)		
Interest on outstanding debt:			
Credit Agreement, net of interest on interest rate swaps	$13,350	$11,961	$8,736
6.5% Senior Notes	19,446	19,506	15,716
6.25% Senior Notes	—	—	2,422
8.25% Senior Notes	2,544	12,380	12,380
Promissory Notes	—	—	543
Amortization of discount and deferred debt issuance costs	1,821	2,120	1,946
Amortization of unrecognized loss attributable to terminated cash flow hedge	—	849	5,095
Commitment fees	450	835	621
Total interest incurred	37,611	47,651	47,459
Less capitalized interest	1,510	641	277

Net interest expense	$36,101	$47,010	$47,182
Cash paid for interest	$39,414	$44,655	$38,476

Note 8: Commitments and Contingencies

We lease certain facilities, pipelines and rights of way under operating leases, most of which contain renewal options. The right of way agreements have various termination dates through 2053.

As of December 31, 2014, the minimum future rental commitments under operating leases having non-cancelable lease terms in excess of one year are as follows:

Years Ending December 31,	(In thousands)
2015	$6,928
2016	6,913
2017	3,549
2018	192
2019	124
Thereafter	266
Total	$17,972

Rental expense charged to operations was $8.0 million, $8.3 million and $8.1 million for the years ended December 31, 2014, 2013 and 2012, respectively.

We also have other long-term contractual obligations primarily consisting of long-term site service agreements with HFC, expiring in 2024 through 2026, for the provision of certain facility services and utility costs that relate to our assets located at HFC’s refinery facilities. At December 31, 2014, these minimum future contractual obligations having terms in excess of one year are as follows:

Years Ending December 31,	(In thousands)
2015	$1,067
2016	1,067
2017	1,067
2018	1,067
2019	1,032
Thereafter	6,294
Total	$11,594

We are a party to various legal and regulatory proceedings, none of which we believe will have a material adverse impact on our financial condition, results of operations or cash flows.

Note 9: Significant Customers

All revenues are domestic revenues, of which 93% are currently generated from our two largest customers: HFC and Alon. The vast majority of our revenues are derived from activities conducted in the southwest United States.

The following table presents the percentage of total revenues generated by each of these customers:

	Years Ended December 31,		
	2014	2013	2012
HFC	83 %	83 %	84 %
Alon	10 %	11 %	11 %

Note 10: Related Party Transactions

We serve HFC's refineries under long-term pipeline and terminal, tankage and throughput agreements expiring from 2019 to 2026. Under these agreements, HFC agrees to transport, store and throughput volumes of refined product and crude oil on our pipelines and terminal, tankage and loading rack facilities that result in minimum annual payments to us. These minimum annual payments or revenues are subject to annual tariff rate adjustments on July 1st each year based on the Producer Price Index ("PPI") or Federal Energy Regulatory Commission ("FERC") index. As of December 31, 2014, these agreements with HFC will result in minimum payments to us of $231.6 million.

If HFC fails to meet its minimum volume commitments under the agreements in any quarter, it will be required to pay us the amount of any shortfall in cash by the last day of the month following the end of the quarter. Under certain of these agreements, a shortfall payment may be applied as a credit in the following four quarters after its minimum obligations are met.

Under certain provisions of an omnibus agreement we have with HFC (the "Omnibus Agreement"), we pay HFC an annual administrative fee ($2.3 million in 2014 and currently $2.4 million) for the provision by HFC or its affiliates of various general and administrative services to us. This fee does not include the salaries of personnel employed by HFC who perform services for us on behalf of HLS or the cost of their employee benefits, which are charged to us separately by HFC. Also, we reimburse HFC and its affiliates for direct expenses they incur on our behalf.

Related party transactions with HFC are as follows:

- Revenues received from HFC were $275.2 million, $252.4 million and $245.6 million for the years ended December 31, 2014, 2013 and 2012, respectively.
- HFC charged us general and administrative services under the Omnibus Agreement of $2.3 million for each of the years ended December 31, 2014, 2013 and 2012.
- We reimbursed HFC for costs of employees supporting our operations of $38.9 million, $34.6 million and $31.1 million for the years ended December 31, 2014, 2013 and 2012, respectively. Netted against the cost of employees for the year ended December 31, 2013, is a $3.5 million refund from HFC related to refunds of taxes covering a multi-year period.
- HFC reimbursed us $16.8 million, $21.6 million and $13.4 million for the years ended December 31, 2014, 2013 and 2012, respectively, for certain reimbursable costs and capital projects.
- We distributed $80.5 million, $71.4 million and $64.0 million, for the years ended December 31, 2014, 2013 and 2012, respectively, to HFC as regular distributions on its common units and general partner interest, including general partner incentive distributions.
- Accounts receivable from HFC were $33.4 million and $29.7 million at December 31, 2014 and 2013, respectively.
- Accounts payable to HFC were $5.2 million and $8.5 million at December 31, 2014 and 2013, respectively.
- Revenues for the years ended December 31, 2014, 2013 and 2012 include $10.1 million, $5.1 million and $7.8 million, respectively, of shortfall payments billed in 2013, 2012 and 2011, respectively, as HFC did not exceed its minimum volume commitment in any of the subsequent four quarters in 2014, 2013 and 2012. Deferred revenue in the consolidated balance sheets at December 31, 2014 and 2013, includes $7.3 million and $10.1 million, respectively, relating to certain shortfall billings. It is possible that HFC may not exceed its minimum obligations to receive credit for any of the $7.3 million deferred at December 31, 2014.
- We acquired from HFC a 75% interest in the UNEV Pipeline in July 2012. See Note 2 for a description of this transaction.

Note 11: Partners' Equity, Income Allocations and Cash Distributions

As of December 31, 2014, HFC held 22,380,030 of our common units and the 2% general partner interest, which together constituted a 39% ownership interest in us.

On January 16, 2013, a two-for-one unit split was paid in the form of a common unit distribution for each issued and outstanding common unit to all unitholders of record on January 7, 2013. All references to unit and per unit amounts in this document and related disclosures have been adjusted to reflect the effect of the unit split for all prior periods presented.

Common Unit Issuances

2013 Issuances

In March 2013, we closed on a public offering of 1,875,000 of our common units. Additionally, an affiliate of HFC, as a selling unitholder, closed on a public sale of 1,875,000 of its HEP common units for which we did not receive any proceeds. We used our net proceeds of $73.4 million to repay indebtedness incurred under our credit facility and for general partnership purposes.

2012 Issuances

On July 12, 2012, we issued HFC 2,059,800 of our common units as partial consideration for our acquisition of its 75% interest in UNEV.

We received aggregate capital contributions of $1.7 million from our general partner to maintain its 2% general partner interest concurrent with the 2012 common unit issuance described above.

Under our registration statement filed with the SEC using a “shelf” registration process, $2.0 billion of securities have been registered. Any potential sale of such securities, through one or more prospectus supplements, would describe, among other things, the specific amounts, prices and terms of any securities offered and how the proceeds would be used. Any proceeds from the sale of securities would be used for general business purposes, which may include, among other things, funding acquisitions of assets or businesses, working capital, capital expenditures, investments in subsidiaries, the retirement of existing debt and/or the repurchase of common units or other securities.

Allocations of Net Income

Net income attributable to HEP is allocated between limited partners and the general partner interest in accordance with the provisions of the partnership agreement. HEP net income allocated to the general partner includes incentive distributions that are declared subsequent to quarter end. After the amount of incentive distributions is allocated to the general partner, the remaining net income attributable to HEP is allocated to the partners based on their weighted-average ownership percentage during the period.

The following table presents the allocation of the general partner interest in net income for the periods presented below:

	Years Ended December 31,		
	2014	2013	2012
	(in thousands)		
General partner interest in net income	$1,446	$1,059	$1,464
General partner incentive distribution	33,221	26,464	20,986
Total general partner interest in net income	$34,667	$27,523	$22,450

Cash Distributions

We consider regular cash distributions to unitholders on a quarterly basis, although there is no assurance as to the future cash distributions since they are dependent upon future earnings, cash flows, capital requirements, financial condition and other factors.

Within 45 days after the end of each quarter, we distribute all of our available cash (as defined in our partnership agreement) to unitholders of record on the applicable record date. The amount of available cash generally is all cash on hand at the end of the quarter; less the amount of cash reserves established by our general partner to provide for the proper conduct of our business, comply with applicable laws, any of our debt instruments, or other agreements; or provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters; plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter.

We make distributions in the following manner: 98% to our common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter and any arrearages in payment of the minimum quarterly distributions for any prior quarters, thereafter. Cash in excess of the minimum quarterly distributions is distributed to the unitholders and the general partner based on certain percentages presented below.

Our general partner, HEP Logistics, is entitled to incentive distributions if the amount we distribute with respect to any quarter exceeds specified target levels.

	Total Quarterly Distribution	Marginal Percentage Interest in Distributions	
	Target Amount	Unitholders	General Partner
Minimum quarterly distribution	$0.25	98%	2%
First target distribution	Up to $0.275	98%	2%
Second target distribution	above $0.275 up to $0.3125	85%	15%
Third target distribution	above $0.3125 up to $0.375	75%	25%
Thereafter	Above $0.375	50%	50%

On January 22, 2015, we announced our cash distribution for the fourth quarter of 2014 of $0.53 per unit. The distribution is payable on all common and general partner units and was paid February 13, 2015, to all unitholders of record on February 2, 2015.

The following table presents the allocation of our regular quarterly cash distributions to the general and limited partners for the periods in which they apply. Our distributions are declared subsequent to quarter end; therefore, the amounts presented do not reflect distributions paid during the periods presented below.

	Years Ended December 31,		
	2014	2013	2012
	(In thousands, except per unit data)		
General partner interest in distribution	$3,264	$2,982	$2,566
General partner incentive distribution	33,221	26,464	20,986
Total general partner distribution	36,485	29,446	23,552
Limited partner distribution	121,714	114,675	102,222
Total regular quarterly cash distribution	$158,199	$144,121	$125,774
Cash distribution per unit applicable to limited partners	$2.075	$1.955	$1.835

As a master limited partnership, we distribute our available cash, which historically has exceeded our net income attributable to HEP because depreciation and amortization expense represents a non-cash charge against income. The result is a decline in our partners' equity since our regular quarterly distributions have exceeded our quarterly net income attributable to HEP. Additionally, if the asset contributions and acquisitions from HFC had occurred while we were not a consolidated variable interest entity of HFC, our acquisition cost, in excess of HFC's historical basis in the transferred assets would have been recorded in our financial statements at the time of acquisition, as increases to our properties and equipment and intangible assets instead of decreases to our partners' equity.

Note 12: Quarterly Financial Data (Unaudited)

Summarized quarterly financial data is as follows:

	First	Second	Third	Fourth	Total
	(In thousands, except per unit data)				
Year Ended December 31, 2014					
Revenues	$87,004	$74,998	$82,130	$88,413	$332,545
Operating income	$45,453	$32,033	$38,925	$38,343	$154,754
Income before income taxes	$27,855	$24,478	$31,231	$30,484	$114,048
Net income	$27,780	$24,450	$31,189	$30,394	$113,813
Net income attributable to Holly Energy Partners	$24,143	$23,034	$29,680	$28,668	$105,525
Limited partners’ per unit interest in net income – basic and diluted	$0.27	$0.25	$0.35	$0.33	$1.20
Distributions per limited partner unit	$0.508	$0.515	$0.523	$0.530	$2.075
Year Ended December 31, 2013					
Revenues	$74,298	$75,285	$77,723	$77,876	$305,182
Operating income	$31,047	$32,520	$34,173	$30,826	$128,566
Income before income taxes	$21,345	$21,641	$23,097	$20,331	$86,414
Net income	$21,289	$21,297	$23,057	$20,438	$86,081
Net income attributable to Holly Energy Partners	$18,399	$20,167	$21,885	$18,998	$79,449
Limited partners’ per unit interest in net income – basic and diluted	$0.21	$0.23	$0.25	$0.19	$0.88
Distributions per limited partner unit	$0.478	$0.485	$0.493	$0.500	$1.955

Note 13: Supplemental Guarantor/Non-Guarantor Financial Information

Obligations of HEP (“Parent”) under the Senior Notes have been jointly and severally guaranteed by each of its direct and indirect 100% owned subsidiaries (“Guarantor Subsidiaries”). These guarantees are full and unconditional, subject to certain customary release provisions. These circumstances include (i) when a Guarantor Subsidiary is sold or sells all or substantially all of its assets, (ii) when a Guarantor Subsidiary is declared “unrestricted” for covenant purposes, (iii) when a Guarantor Subsidiary's guarantee of other indebtedness is terminated or released and (iv) when the requirements for legal defeasance or covenant defeasance or to discharge the Senior Notes have been satisfied.

The following financial information presents condensed consolidating balance sheets, statements of comprehensive income, and statements of cash flows of the Parent, the Guarantor Subsidiaries and the Non-Guarantor subsidiaries. The information has been presented as if the Parent accounted for its ownership in the Guarantor Subsidiaries and the Guarantor Restricted Subsidiaries accounted for the ownership of the Non-Guarantor Non-Restricted Subsidiaries, using the equity method of accounting.

Condensed Consolidating Balance Sheet

December 31, 2014	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Current assets:					
Cash and cash equivalents	$2	$2,828	$ —	$ —	$2,830
Accounts receivable	—	34,274	6,044	(189)	40,129
Prepaid and other current assets	212	2,856	1,315	—	4,383
Total current assets	214	39,958	7,359	(189)	47,342
Properties and equipment, net	—	596,988	383,491	—	980,479
Investment in subsidiaries	622,100	285,247	—	(907,347)	—
Transportation agreements, net	—	80,703	—	—	80,703
Goodwill	—	256,498	—	—	256,498
Investment in SLC Pipeline	—	24,478	—	—	24,478
Other assets	1,319	10,736	—	—	12,055
Total assets	$623,633	$1,294,608	$ 390,850	$ (907,536)	$1,401,555
LIABILITIES AND PARTNERS' EQUITY					
Current liabilities:					
Accounts payable	$—	$15,495	$ 2,575	$ (189)	$17,881
Accrued interest	6,500	115	—	—	6,615
Deferred revenue	—	5,672	6,760	—	12,432
Accrued property taxes	—	1,902	801	—	2,703
Other current liabilities	45	4,408	118	—	4,571
Total current liabilities	6,545	27,592	10,254	(189)	44,202
Long-term debt	296,579	571,000	—	—	867,579
Other long-term liabilities	147	17,731	267	—	18,145
Deferred revenue	—	29,392	—	—	29,392
Class B unit	—	26,793	—	—	26,793
Equity - partners	320,362	622,100	380,329	(1,002,429)	320,362
Equity - noncontrolling interest	—	—	—	95,082	95,082
Total liabilities and partners' equity	$623,633	$1,294,608	$ 390,850	$ (907,536)	$1,401,555

Condensed Consolidating Balance Sheet

December 31, 2013	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Current assets:					
Cash and cash equivalents	$2	$1,447	$ 4,903	$—	$6,352
Accounts receivable	—	31,107	4,543	(914)	34,736
Intercompany accounts receivable	—	62,516	—	(62,516)	—
Prepaid and other current assets	234	2,590	1,050	—	3,874
Total current assets	236	97,660	10,496	(63,430)	44,962
Properties and equipment, net	—	564,847	392,967	—	957,814
Investment in subsidiaries	885,598	292,464	—	(1,178,062)	—
Transportation agreements, net	—	87,650	—	—	87,650
Goodwill	—	256,498	—	—	256,498
Investment in SLC Pipeline	—	24,741	—	—	24,741
Other assets	1,684	9,159	—	—	10,843
Total assets	$887,518	$1,333,019	$ 403,463	$(1,241,492)	$1,382,508
LIABILITIES AND PARTNERS' EQUITY					
Current liabilities:					
Accounts payable	$—	$18,966	$ 4,846	$(914)	$22,898
Intercompany accounts payable	62,516	—	—	(62,516)	—
Accrued interest	10,198	41	—	—	10,239
Deferred revenue	—	6,406	7,575	—	13,981
Accrued property taxes	—	1,661	942	—	2,603
Other current liabilities	629	1,216	—	—	1,845
Total current liabilities	73,343	28,290	13,363	(63,430)	51,566
Long-term debt	444,630	363,000	—	—	807,630
Other long-term liabilities	99	14,338	148	—	14,585
Deferred revenue	—	21,669	—	—	21,669
Class B unit	—	20,124	—	—	20,124
Equity - partners	369,446	885,598	389,952	(1,275,550)	369,446
Equity - noncontrolling interest	—	—	—	97,488	97,488
Total liabilities and partners' equity	$887,518	$1,333,019	$ 403,463	$(1,241,492)	$1,382,508

Condensed Consolidating Statement of Comprehensive Income

Year Ended December 31, 2014	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Revenues:					
Affiliates	$—	$254,364	$ 22,073	$ (1,241)	$275,196
Third parties	—	45,711	11,638	—	57,349
	—	300,075	33,711	(1,241)	332,545
Operating costs and expenses:					
Operations (exclusive of depreciation and amortization)	—	93,382	12,660	(1,241)	104,801
Depreciation and amortization	—	47,592	14,574	—	62,166
General and administrative	2,658	8,166	—	—	10,824
	2,658	149,140	27,234	(1,241)	177,791
Operating income (loss)	(2,658)	150,935	6,477	—	154,754
Equity in earnings of subsidiaries	138,691	4,858	—	(143,549)	—
Equity in earnings of SLC Pipeline	—	2,987	—	—	2,987
Interest income	—	3	—	—	3
Interest expense	(22,831)	(13,270)	—	—	(36,101)
Loss on early extinguishment of debt	(7,677)	—	—	—	(7,677)
Other	—	82	—	—	82
	108,183	(5,340)	—	(143,549)	(40,706)
Income (loss) before income taxes	105,525	145,595	6,477	(143,549)	114,048
State income tax expense	—	(235)	—	—	(235)
Net income (loss)	105,525	145,360	6,477	(143,549)	113,813
Allocation of net (income) attributable to noncontrolling interests	—	—	—	(8,288)	(8,288)
Net income (loss) attributable to Holly Energy Partners	105,525	145,360	6,477	(151,837)	105,525
Other comprehensive (loss)	98	98	—	(98)	98
Comprehensive income (loss)	$105,623	$145,458	$ 6,477	$ (151,935)	$105,623

Condensed Consolidating Statement of Comprehensive Income

Year Ended December 31, 2013	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Revenues:					
Affiliates	$—	$236,336	$ 17,258	$ (1,226)	$252,368
Third parties	—	42,139	10,675	—	52,814
	—	278,475	27,933	(1,226)	305,182
Operating costs and expenses:					
Operations (exclusive of depreciation and amortization)	—	88,614	12,056	(1,226)	99,444
Depreciation and amortization	—	51,082	14,341	—	65,423
General and administrative	3,381	8,368	—	—	11,749
	3,381	148,064	26,397	(1,226)	176,616
Operating income (loss)	(3,381)	130,411	1,536	—	128,566
Equity in earnings of subsidiaries	115,850	1,231	—	(117,081)	—
Equity in earnings of SLC Pipeline	—	2,826	—	—	2,826
Interest income	—	56	105	—	161
Interest expense	(33,020)	(13,990)	—	—	(47,010)
Gain on sale of assets	—	1,810	—	—	1,810
Other	—	61	—	—	61
	82,830	(8,006)	105	(117,081)	(42,152)
Income (loss) before income taxes	79,449	122,405	1,641	(117,081)	86,414
State income tax expense	—	(333)	—	—	(333)
Net income (loss)	79,449	122,072	1,641	(117,081)	86,081
Allocation of net loss attributable to noncontrolling interests	—	—	—	(6,632)	(6,632)
Net income (loss) attributable to Holly Energy Partners	79,449	122,072	1,641	(123,713)	79,449
Other comprehensive income	4,135	4,135	—	(4,135)	4,135
Comprehensive income (loss)	$83,584	$126,207	$ 1,641	$ (127,848)	$83,584

Condensed Consolidating Statement of Comprehensive Income

Year Ended December 31, 2012	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Revenues:					
Affiliates	$—	$232,986	$ 13,754	$ (1,158)	$245,582
Third parties	—	41,984	4,994	—	46,978
	—	274,970	18,748	(1,158)	292,560
Operating costs and expenses:					
Operations (exclusive of depreciation and amortization)	—	78,766	11,634	(1,158)	89,242
Depreciation and amortization	—	43,147	14,314	—	57,461
General and administrative	3,336	4,258	—	—	7,594
	3,336	126,171	25,948	(1,158)	154,297
Operating income (loss)	(3,336)	148,799	(7,200)	—	138,263
Equity in earnings (loss) of subsidiaries	130,743	(5,400)	—	(125,343)	—
Equity in earnings of SLC Pipeline	—	3,364	—	—	3,364
Interest expense	(31,523)	(15,659)	—	—	(47,182)
Loss on early extinguishment of debt	(2,979)	—	—	—	(2,979)
Other	—	10	—	—	10
	96,241	(17,685)	—	(125,343)	(46,787)
Income (loss) before income taxes	92,905	131,114	(7,200)	(125,343)	91,476
State income tax expense	—	(371)	—	—	(371)
Net income (loss)	92,905	130,743	(7,200)	(125,343)	91,105
Allocation of net loss attributable to Predecessors	4,200	—	—	—	4,200
Allocation of net loss attributable to noncontrolling interests	(2,953)	—	—	1,800	(1,153)
Net income (loss) attributable to Holly Energy Partners	94,152	130,743	(7,200)	(123,543)	94,152
Other comprehensive (loss)	2,185	2,185	—	(2,185)	2,185
Comprehensive income (loss)	$96,337	$132,928	$ (7,200)	$ (125,728)	$96,337

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2014	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Cash flows from operating activities	$(25,339)	$193,273	$ 19,398	$ (692)	$186,640
Cash flows from investing activities					
Additions to properties and equipment	—	(71,758)	(8,201)	—	(79,959)
Distributions from UNEV	—	11,383	—	(11,383)	—
Distributions in excess of equity in earnings in SLC Pipeline	—	263	—	—	263
	—	(60,112)	(8,201)	(11,383)	(79,696)
Cash flows from financing activities					
Net borrowings under credit agreement	—	208,000	—	—	208,000
Net intercompany financing activities	339,771	(339,771)	—	—	—
Repayments of senior notes	(156,188)	—	—	—	(156,188)
Distributions to HEP unitholders	(154,670)	—	—	—	(154,670)
Distributions to noncontrolling interests	—	—	(16,100)	12,075	(4,025)
Purchase of units for incentive grants	(3,577)	—	—	—	(3,577)
Other	3	(9)	—	—	(6)
	25,339	(131,780)	(16,100)	12,075	(110,466)
Cash and cash equivalents					
Increase (decrease) for the period	—	1,381	(4,903)	—	(3,522)
Beginning of period	2	1,447	4,903	—	6,352
End of period	$2	$2,828	$ —	$ —	$2,830

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2013	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Cash flows from operating activities	$(34,605)	$197,678	$ 20,007	$—	$183,080
Cash flows from investing activities					
Additions to properties and equipment	—	(45,085)	(7,016)	—	(52,101)
Proceeds from the sale of assets	—	2,731	—	—	2,731
Distributions from UNEV	—	9,375	—	(9,375)	—
Distribution in excess of equity in earnings in SLC Pipeline	—	300	—	—	300
	—	(32,679)	(7,016)	(9,375)	(49,070)
Cash flows from financing activities					
Net repayments under credit agreement	—	(58,000)	—	—	(58,000)
Net intercompany financing activities	105,031	(105,031)	—	—	—
Proceeds from issuance of common units	73,444	—	—	—	73,444
Distributions to noncontrolling interests	—	—	(12,500)	9,375	(3,125)
Contributions from general partner	1,499	—	—	—	1,499
Distributions to HEP unitholders	(139,486)	—	—	—	(139,486)
Purchase of units for restricted grants	(5,634)	—	—	—	(5,634)
Deferred financing costs	—	(1,344)	—	—	(1,344)
Other	(249)	—	—	—	(249)
	34,605	(164,375)	(12,500)	9,375	(132,895)
Cash and cash equivalents					
Increase for the period	—	624	491	—	1,115
Beginning of period	2	823	4,412	—	5,237
End of period	$2	$1,447	$ 4,903	$—	$6,352

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2012	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
Cash flows from operating activities	$(34,557)	$194,667	$ 1,039	$—	$161,149
Cash flows from investing activities					
Additions to properties and equipment	—	(28,134)	(14,727)	—	(42,861)
Distributions in excess of equity in earnings in SLC Pipeline	—	262	—	—	262
	—	(27,872)	(14,727)	—	(42,599)
Cash flows from financing activities					
Net borrowings under credit agreement	—	221,000	—	—	221,000
Proceeds from issuance of senior notes	294,750	—	—	—	294,750
Net intercompany financing activities	51,989	(51,989)	—	—	—
Cash distribution to HFC for UNEV acquisition	—	(260,922)	—	—	(260,922)
Redemption of senior notes	(185,000)	(75,235)	—	—	(260,235)
Contributions from UNEV joint venture partners	—	—	15,000	—	15,000
Contributions from general partner	1,748	—	—	—	1,748
Distributions to HEP unitholders	(122,777)	—	—	—	(122,777)
Purchase of units for restricted grants	(5,240)	321	—	—	(4,919)
Deferred financing costs	(913)	(2,325)	—	—	(3,238)
Other	—	(89)	—	—	(89)
	34,557	(169,239)	15,000	—	(119,682)
Cash and cash equivalents					
Increase (decrease) for the period	—	(2,444)	1,312	—	(1,132)
Beginning of period	2	3,267	3,100	—	6,369
End of period	$2	$823	$ 4,412	$—	$5,237

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

We have had no change in, or disagreement with, our independent registered public accounting firm on matters involving accounting and financial disclosure.

Item 9A. Controls and Procedures

(a) Evaluation of disclosure controls and procedures

Our principal executive officer and principal financial officer have evaluated, as required by Rule 13a-15(b) under the Securities Exchange Act of 1934 (the “Exchange Act”), our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this annual report on Form 10-K. Our disclosure controls and procedures are designed to provide reasonable assurance that the information we are required to disclose in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of December 31, 2014, at a reasonable level of assurance.

(b) Changes in internal control over financial reporting

There have been no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

See Item 8 for “Management’s Report on its Assessment of the Partnership’s Internal Control Over Financial Reporting” and “Report of Independent Registered Public Accounting Firm.”

Item 9B. Other Information

There have been no events that occurred in the fourth quarter of 2014 that would need to be reported on Form 8-K that have not been previously reported.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Holly Logistic Services, L.L.C. (“HLS”), the general partner of HEP Logistics Holdings, L.P. (“HEP Logistics”), our general partner, manages our operations and activities. Neither our general partner nor our directors are elected by our unitholders. Unitholders are not entitled to directly or indirectly participate in our management or operations. The sole member of HLS, which is a subsidiary of HFC, appoints the directors of HLS to serve until their death, resignation or removal.

Our general partner owes a fiduciary duty to our unitholders. Our general partner is liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically non-recourse to it. Whenever possible, our general partner intends to incur indebtedness or other obligations that are non-recourse.

Executive Officers

The following sets forth information regarding the executive officers of HLS as of February 13, 2015:

Name	Age	Position with HLS
Michael C. Jennings	49	Chief Executive Officer
Bruce R. Shaw	47	President
Douglas S. Aron	41	Executive Vice President and Chief Financial Officer
Mark T. Cunningham	55	Senior Vice President, Operations
Denise C. McWatters	55	Senior Vice President, General Counsel and Secretary

Certain executive officers of HLS are also officers of HFC or provide services to HFC. During 2014, Messrs. Shaw and Cunningham were the only HLS executive officers who spent all of their professional time managing our business and affairs. Messrs. Jennings and Aron and Ms. McWatters are also officers of HFC and devoted as much of their professional time in 2014 as was necessary to oversee the management of our business and affairs.

Information regarding Mr. Jennings is included below under “Directors.”

Bruce R. Shaw was appointed President in November 2012. Mr. Shaw served as Senior Vice President and Chief Financial Officer from December 2011 until November 2012, Senior Vice President, Strategy and Corporate Development from July 2011 until December 2011, Senior Vice President and Chief Financial Officer from January 2008 until July 2011, and Vice President, Corporate Development from August 2004 to January 2007. Mr. Shaw served as Senior Vice President, Strategy and Corporation Development of HFC from July 2011 through December 2012, Senior Vice President and Chief Financial Officer of Holly Corporation from 2008 until the effective time of the merger between Holly Corporation and Frontier Oil Corporation in July 2011, and Vice President, Special Projects for Holly Corporation from September 2007 to December 2007. Mr. Shaw served on the Board of HLS from April 2007 to April 2008. Mr. Shaw briefly left Holly Corporation in June 2007 and served as President of Standard Supply and Distributing Company, Inc. and Bartos Industries, Ltd., two companies that are affiliated with each other in the heating, ventilation, and air conditioning industry. Mr. Shaw previously served Holly Corporation in various positions with increasing seniority from 1997 to 2007. Prior to joining Holly Corporation, Mr. Shaw was a consultant at McKinsey & Company, a global management consulting firm.

Douglas S. Aron was appointed Executive Vice President and Chief Financial Officer in November 2012. He previously served in such position from July 2011 until December 2011. Mr. Aron currently also serves as Executive Vice President and Chief Financial Officer of HFC since the merger of Holly Corporation and Frontier Oil Corporation in July 2011. Prior to joining HFC, Mr. Aron was Executive Vice President and Chief Financial Officer of Frontier Oil Corporation from 2009 until 2011. Additionally, he served as Vice President-Corporate Finance of Frontier Oil Corporation from 2005 to 2009 and Director-Investor Relations from 2001 to 2005. Prior to joining Frontier Oil Corporation, Mr. Aron was a lending officer for Amegy Bank.

Mark T. Cunningham was appointed Senior Vice President, Operations in January 2013. He previously served as Vice President, Operations from July 2007 to January 2013. He served Holly Corporation as Senior Manager of Special Projects from December 2006 through June 2007 and as Senior Manager of Integrity Management and Environmental, Health and Safety from July 2004 through December 2006. Prior to joining Holly Corporation, Mr. Cunningham served Diamond Shamrock/Ultramar Diamond Shamrock for 20 years in several engineering and pipeline operations capacities.

Denise C. McWatters was appointed Senior Vice President, General Counsel and Secretary in January 2013. Ms. McWatters also serves in a similar capacity for HFC. Ms. McWatters previously served as Vice President, General Counsel and Secretary from April 2008 until January 2013. She joined Holly Corporation in October 2007 with more than 20 years of legal experience and served as Deputy General Counsel of Holly Corporation until April 2008 and as Vice President, General Counsel and Secretary of HFC (formerly Holly Corporation) from April 2008 until January 2013. Ms. McWatters served as the General Counsel of The Beck Group from 2005 through 2007. Prior to joining The Beck Group, Ms. McWatters practiced law in various capacities at the predecessor firm to Locke Lord Bissell & Liddell LLP, the Law Offices of Denise McWatters, the legal department at Citigroup, N.A., and the law firm of Cox Smith Matthews Incorporated.

Board Leadership Structure

The Board of Directors of HLS (the "Board") is responsible for selecting the Board leadership structure that is in the best interest of HLS and HEP. Effective January 1, 2014, the Board separated the positions of Chairman and Chief Executive Officer. Currently, Mr. Clifton serves as Chairman of the Board in a non-employee capacity, and Mr. Jennings serves as the Chief Executive Officer of HLS. The Board believes that at this time the separation of these positions enhances the oversight of management by the Board and HLS's and HEP's overall leadership structure. In addition, as a result of his former role as HLS's Chief Executive Officer, Mr. Clifton has company-specific experience and expertise and as Chairman of the Board can identify strategic priorities, lead the discussion and execution of strategy, and facilitate the flow of information between management and the Board.

Presiding Director

Mr. Charles M. Darling, IV was appointed by the non-employee directors of HLS to serve as the lead independent director (the "Presiding Director") of the Board. The Presiding Director has the following responsibilities:

- presiding at all executive sessions of the non-employee directors of the Board;
- consulting with management on Board and committee meeting agendas;
- acting as a liaison in appropriate instances between management and the non-employee directors, including advising the Chairman and the Chief Executive Officer on the efficiency of the Board meetings; and
- facilitating teamwork and communication between the non-employee directors and management.

Persons wishing to communicate with the non-employee directors are invited to email the Presiding Director at presiding.director.HEP@hollyenergy.com or write to: Charles M. Darling, IV, Presiding Director, c/o Secretary, Holly Logistic Services, L.L.C., 2828 N. Harwood, Suite 1300, Dallas, Texas 75201-1507. The Secretary will forward all communication to the appropriate director or directors, other than those communications that are merely solicitations for products or services or relate to matters that are of a type that are clearly improper or irrelevant to the functioning of the Board or the business and affairs of HLS and HEP.

Risk Management

The Board has an active role in overseeing management of the risks affecting HLS and HEP. The Board regularly reviews information regarding HLS and HEP’s credit, liquidity and business and operations, as well as the risks associated with each. The Board committees are also engaged in overseeing risk associated with HLS and HEP.

- The Compensation Committee oversees the management of risks relating to HLS’s executive compensation plans and arrangements.

- The Audit Committee oversees management of financial reporting and controls risks.

- The Conflicts Committee oversees specific matters that the Board or the Conflicts Committee believes may involve conflicts of interest with HFC.

While each committee is responsible for evaluating certain risks and overseeing the management of such risks, the entire Board is ultimately responsible for the risk management of HLS and HEP and is regularly informed through committee reports about such risks.

The sole member of HLS manages risks associated with the independence of the Board. The Audit Committee and the Board also receive input and reports from HLS's risk management oversight committee on management's views of the risks facing HLS and HEP. The risk management oversight committee is made up of management personnel, none of whom serve on the Board and all of whom have a range of different backgrounds, skills and experiences with regard to the operational, financial and strategic risk profile of HLS and HEP. The risk management oversight committee monitors the risk environment for HLS and HEP as a whole, and reviews the activities that mitigate risks to an achievable and acceptable level.

Director Qualifications

The Board believes that it is necessary for each of HLS's directors to possess a variety of qualities and skills. When searching for new candidates, the sole member of HLS considers the evolving needs of the Board and searches for candidates that fill any current or anticipated future needs. The Board also believes that all directors must possess a considerable amount of business management, business leadership and educational experience. When considering director candidates, the sole member of HLS first considers a candidate's management experience and then considers issues of judgment, background, stature, conflicts of interest, integrity, ethics and commitment to the goal of maximizing unitholder value. The sole member of HLS also focuses on issues of diversity, such as diversity of education, professional experience and differences in viewpoints and skills. The sole member of HLS does not have a formal policy with respect to diversity; however, the Board and the sole member of HLS believe that it is essential that the Board members represent diverse viewpoints. In considering candidates for the Board, the sole member of HLS considers the entirety of each candidate's credentials in the context of these standards. All our directors bring to the Board executive leadership experience derived from their service in many areas.

Director Independence

The Board has determined that Messrs. Darling, William J. Gray, Jerry W. Pinkerton, P. Dean Ridenour, William P. Stengel and James G. Townsend meet the applicable criteria for independence under the currently applicable rules of the New York Stock Exchange.

Audit Committee. The Audit Committee of HLS is composed of three directors, Messrs. Pinkerton, Ridenour and Darling. The Board has determined that each member of the Audit Committee is "independent" as defined by the New York Stock Exchange listing standards and Rule 10A-3 of the Securities Exchange Act of 1934 (the "Exchange Act").

Conflicts Committee. The Conflicts Committee of HLS is composed of four directors, Messrs. Stengel, Pinkerton, Gray and Townsend. The Board has determined that each member of the Conflicts Committee is "independent" as defined by the New York Stock Exchange listing standards and Rule 10A-3 of the Exchange Act, as required by the Conflicts Committee Charter.

Compensation Committee. The Compensation Committee of HLS is composed of five directors, Messrs. Jennings, Darling, Gray, Stengel and Townsend. The Board has determined that each of Messrs. Darling, Gray, Stengel and Townsend is "independent" as defined by the New York Stock Exchange listing standards. Because we are a master limited partnership, Rule 303A.05 of the New York Stock Exchange Listed Company Manual, which requires a publicly traded company to have a compensation committee composed entirely of independent directors, does not apply to us.

Independence Determinations. In making its independence determinations, the Board considered certain transactions, relationships and arrangements. In determining Mr. Ridenour's independence, the Board considered that Mr. Ridenour has not been employed by HFC or HLS since 2008 and has not received compensation in excess of $120,000 since 2009. In determining Mr. Townsend's independence, the Board considered that Mr. Townsend has not been employed by HFC or HLS since 2011 and has not received compensation in excess of $120,000 since 2011. The Board has determined that these historical relationships do not impair Mr. Ridenour's or Mr. Townsend's independence. In addition, in determining Mr. Clifton's and Mr. Gray's independence, the Board considered the consulting fees each of them receives from HFC and determined that such consulting fees do not impair their independence.

Code of Ethics

HLS has adopted a Code of Business Conduct and Ethics that applies to all of its officers, directors and employees, including HLS's principal executive officer, principal financial officer, and principal accounting officer. The purpose of the Code of Business Conduct and Ethics is to, among other things, affirm HLS's and HEP's commitment to a high standard of integrity and ethics. The Code sets forth a common set of values and standards to which all of HLS's officers, directors and employees must adhere. We will post information regarding an amendment to, or a waiver from, the Code of Business Conduct and Ethics on our website.

Copies of our Governance Guidelines, Audit Committee Charter, Compensation Committee Charter, and Code of Business Conduct and Ethics are available on our website at www.hollyenergy.com. Copies of these documents may also be obtained free of charge upon written request to Holly Energy Partners, L.P., Attention: Vice President, Investor Relations, 2828 N. Harwood, Suite 1300, Dallas, Texas, 75201-1507.

The Board, Its Committees and Director Compensation

Directors

The following individuals serve as directors of HLS:

Matthew P. Clifton Director since July 2004. Age 63.

Principal Occupation: Chairman of the Board of HLS

Business Experience:	Mr. Clifton has served as Chairman of the Board of HLS, in a non-employee capacity, since February 2014. Mr. Clifton also serves as a consultant for HFC since June 2014. Mr. Clifton previously served as Executive Chairman of HLS from January 2014 until his retirement in February 2014, as Chairman of the Board and Chief Executive Officer of HLS from March 2004 through December 2013 and as President of HLS from July 2011 to November 2012. Mr. Clifton joined Holly Corporation in 1980 and served as the Executive Chairman of HFC from July 2011 through December 2012. Mr. Clifton previously served as Chief Executive Officer of Holly Corporation from 2006 until the merger with Frontier Oil Corporation in July 2011, as Chairman of the Board of Holly Corporation from April 2007 until the merger with Frontier Oil Corporation in July 2011 and as President of Holly Corporation from 1995 until 2006.

Additional Directorships: Mr. Clifton served as a director of HFC from 1995 through December 2012.

Qualifications:	Mr. Clifton has extensive knowledge of the operations of HLS and HEP, the refining industry and macro-economic conditions, as well as valuable industry relationships throughout the country. Mr. Clifton brings a unique and valuable perspective as well as an understanding of HLS's and HEP's history, culture, vision and strategy to the Board.

Charles M. Darling, IV Director since July 2004. Age 66.

Principal Occupation: President of DQ Holdings, L.L.C.

Business Experience:	Mr. Darling has served as President of DQ Holdings, L.L.C., a venture capital investment and consulting firm focused primarily on opportunities in the energy industry, since August 1998. Mr. Darling was previously the General Manager of Desert Power, LP and of its general partner, Desert Power, LLC, which was an indirect affiliate of DQ Holdings, L.L.C. In late 2006, Desert Power, LLC and Desert Power, LP, along with certain of their subsidiaries, filed for bankruptcy in Nevada. In late 2007, the bankruptcy court approved the plan of reorganization, which became final in accordance with its terms in early 2008. Mr. Darling also previously practiced law at the law firm of Baker Botts, L.L.P. for over 20 years.
Qualifications:	Mr. Darling has significant experience addressing financial, legal, regulatory and risk matters affecting HLS and HEP. His service as a partner of a major international law firm practicing energy law, as President and General Counsel of a publicly traded energy company with a publicly traded pipelines

master limited partnership and his subsequent endeavors in the energy industry as President of an investment and development firm provide him with valuable insight into our industry. Mr. Darling's leadership skills, management and legal experience make him particularly well suited to be our Presiding Director.

William J. Gray Director since April 2008. Age 74.

Principal Occupation: Private Consultant

Business Experience:	Mr. Gray is a private consultant. He served as a member of the New Mexico House of Representatives from November 2006 until January 2015. Mr. Gray has served as a governmental affairs consultant for HFC since January 2003. He also served as a consultant to Holly Corporation from October 1999 through September 2001. Mr. Gray served as a director of Holly Corporation from September 1996 until May 2008. Mr. Gray was employed by Holly Corporation for over 30 years and retired in October 1999 at which time Mr. Gray was Senior Vice President, Marketing and Supply.
Qualifications:	Mr. Gray brings to the Board forty years of experience in pipeline, refining, and marketing and supply. Mr. Gray also brings business and management expertise and extensive knowledge of, and a unique perspective on, regulatory matters affecting our industry as a result of his government experience.

Michael C. Jennings Director since October 2011. Age 49.

Principal Occupation: Chief Executive Officer and President of HFC and Chief Executive Officer of HLS

Business Experience:	Mr. Jennings was appointed as Chief Executive Officer of HLS in January 2014. Mr. Jennings has served as the Chief Executive Officer and President of HFC since the merger of Holly Corporation and Frontier Oil Corporation in July 2011 and as Chairman of the Board of HFC since January 2013. Mr. Jennings previously served as the President and Chief Executive Officer of Frontier Oil Corporation from 2009 until the merger in July 2011 and as the Executive Vice President and Chief Financial Officer of Frontier Oil Corporation from 2005 until 2009.
Additional Directorships:	Mr. Jennings currently serves as the Chairman of the Board and a director of HFC and a director of ION Geophysical Corporation. Mr. Jennings served as a director of Frontier Oil Corporation from 2008 until the merger in July 2011 and as Chairman of the board of directors of Frontier Oil Corporation from 2010 until the merger in July 2011.
Qualifications:	Mr. Jennings provides valuable and extensive industry knowledge and experience. His knowledge of the day-to-day operations of HFC provides a significant resource for the Board and facilitates discussions between the Board and HFC management.

Jerry W. Pinkerton	Director since July 2004. Age 74.

Principal Occupation: Retired

Business Experience:	Mr. Pinkerton retired in December 2003. From December 2000 to December 2003, Mr. Pinkerton served as a consultant to TXU Corp. (now Energy Future Holdings Corp.), and from August 1997 to December 2000, Mr. Pinkerton served as Controller of TXU Corp. and its U.S. subsidiaries. Mr. Pinkerton previously served as the Vice President and Chief Accounting Officer of ENSERCH Corporation and was employed for 26 years as an auditor by Deloitte Haskins & Sells, a predecessor firm of Deloitte & Touche, LLP, including 15 years as an audit partner.
Additional Directorships:	Since April 2012, Mr. Pinkerton has served on the board of directors of Southcross Energy Partners GP, LLC, the general partner of Southcross Energy Partners, L.P., and serves as the chair of the audit and conflicts committees of the board of directors of Southcross Energy Partners GP, LLC. Mr. Pinkerton served on the board of directors of Animal Health International, Inc., and served as chair of its audit committee, from May 2008 to June 2011.
Qualifications:	Mr. Pinkerton brings to the Board his audit, accounting and financial reporting expertise and a level of financial sophistication that qualifies him as an audit committee financial expert. Due to his executive management experience with public companies and public accounting firms, Mr. Pinkerton possesses business and management expertise that provide an invaluable insight into HLS's and HEP's business.

P. Dean Ridenour	Director since August 2004. Age 73.

Principal Occupation: Retired

Business Experience:	Mr. Ridenour retired in February 2010. Mr. Ridenour provided consulting services to Holly Corporation from January 2008 until February 2010, and served as Vice President and Chief Accounting Officer of Holly Corporation and HLS from January 2005 to January 2008. Mr. Ridenour served as Vice President, Special Projects of Holly Corporation from August 2004 to December 2004 and prior to becoming a full-time employee, provided full-time consulting services to Holly Corporation beginning in October 2002. Mr. Ridenour was employed for 34 years by Ernst & Young LLP, including 20 years as an audit partner, prior to retiring from such position in 1997.
Qualifications:	Mr. Ridenour's management experience and his accounting and financial reporting expertise qualify him as an audit committee financial expert and make him a valuable member of the Board. In addition, Mr. Ridenour's prior experience at HLS and Holly Corporation provide him with a deep understanding of our business and industry.

William P. Stengel	Director since July 2004. Age 66.

Principal Occupation: Retired

Business Experience:	Mr. Stengel retired in May 2003. From 1997 to May 2003, Mr. Stengel served as Managing Director of the global energy and mining group at Citigroup/Citibank, N.A.

Qualifications:	Mr. Stengel's executive management experience in public companies, banking and financial expertise, and general business and management expertise provides him with significant insight into our operations, management and finance.

James G. Townsend Director since January 2012. Age 60.

Principal Occupation: Member of the New Mexico House of Representatives

Business Experience:	Mr. Townsend has served as a member of the New Mexico House of Representatives since January 2015. Mr. Townsend retired from HFC in December 2011. He was employed by Holly Corporation (and HFC) and/or HLS for more than 25 years. From 2008 until his retirement, Mr. Townsend served as Senior Vice President of UNEV Pipeline, LLC, a joint venture between Sinclair Oil Corporation and a subsidiary of HEP. Mr. Townsend served as Vice President, Operations for HLS from 2004 to 2007 and was responsible for all pipeline and terminal operations for Holly Corporation prior to the formation of HEP. Prior to such time, Mr. Townsend served in positions of increasing seniority at Holly Corporation.
Qualifications:	Mr. Townsend brings to the Board his knowledge of the operations of HFC, HLS and their subsidiaries, his 25 years of experience in the industry, and his business expertise.

None of our directors reported any litigation for the period from 2005 to 2015 that is required to be reported in this Annual Report on Form 10-K.

The Board

Under the Company's Governance Guidelines, Board members are expected to prepare for, attend and participate in all meetings of the Board and Board committees on which they serve. During 2014, the Board held ten meetings. Each director attended at least 75% of the total number of meetings of the Board and committees on which he served.

Board Committees

The Board currently has four standing committees:

- an Audit Committee;
- a Compensation Committee;
- a Conflicts Committee; and
- an Executive Committee.

Other than the Executive Committee, each of these committees operates under a written charter adopted by the Board.

During 2014, the Audit Committee held eight meetings, the Conflicts Committee held five meetings and the Compensation Committee held four meetings.

The Board appoints committee members annually. The following table sets forth the current composition of our committees:

Name	Executive Committee	Audit Committee	Compensation Committee	Conflicts Committee
Matthew P. Clifton	x (Chair)			
Charles M. Darling, IV		x	x (1)	
William J. Gray			x	x
Michael C. Jennings	x		x (Chair)	
Jerry W. Pinkerton	x	x (Chair)		x

P. Dean Ridenour		x		
William P. Stengel	x		x	x (Chair)
James G. Townsend			x	x

(1) Mr. Darling serves as the chairman of the subcommittee of the Compensation Committee.

Audit Committee

The functions of the Audit Committee include the following:

- selecting our independent registered public accounting firm and reviewing the professional services they provide;
- reviewing the scope of the audit performed by the independent registered public accounting firm;
- overseeing matters related to the internal audit function;
- reviewing the audit report issued by the independent auditor;
- reviewing HEP's annual and quarterly financial statements;
- reviewing any material comments contained in the auditor's letters to management;
- reviewing HEP's internal accounting controls; and
- reviewing the type and extent of any non-audit work to be performed by the independent registered public accounting firm and its compatibility with their continued objectivity and independence.

Each member of the Audit Committee has the ability to read and understand fundamental financial statements. The Board has determined that Messrs. Pinkerton and Ridenour meet the requirements of an "audit committee financial expert" as defined by the rules of the SEC.

Conflicts Committee

The functions of the Conflicts Committee include reviewing specific matters that the Board or the Conflicts Committee believes may involve conflicts of interest with HFC. The Conflicts Committee determines if the resolution of the conflict of interest is fair and reasonable to HEP. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties it may owe us or our unitholders.

Compensation Committee

The functions of the Compensation Committee include:

- reviewing, evaluating and approving the agreements, plans, policies and programs of HLS and HEP;
- discharging the Board's responsibilities relating to compensation of HLS's officers and directors;
- overseeing the preparation of the Compensation Discussion and Analysis to be included in the Annual Report and preparing the Compensation Committee Report to be included in the Annual Report; and
- administering HEP's equity plan and HLS's annual incentive plan.

The Compensation Committee has appointed a subcommittee comprised of four directors, Messrs. Darling, Gray, Stengel and Townsend, all of whom are "independent" as defined by the New York Stock Exchange listing standards, for purposes of approving equity awards, including performance goals applicable to such awards, if applicable, and any other matters that are within the responsibilities of the Compensation Committee requiring approval solely by independent members of the Board. During 2014, the subcommittee of the Compensation Committee held four meetings.

The Compensation Committee has engaged Frederic W. Cook & Co. (the “Compensation Consultant” or “FWC”), an executive compensation consulting firm, to advise it regarding the compensation of HLS’s officers and directors. In selecting FWC as its independent compensation consultant, the Compensation Committee assessed the independence of FWC pursuant to SEC rules and considered, among other things, whether FWC provides any other services to HLS or us, the fees paid by us to FWC as a percentage of FWC’s total revenues, the policies of FWC that are designed to prevent any conflict of interest between FWC, the Compensation Committee, HLS and us, any personal or business relationship between FWC and a member of the Compensation Committee or one of HLS’s executive officers and whether FWC owned any of our common units. In addition to the foregoing, the Compensation Committee received an independence letter from FWC, as well as other documentation addressing the firm's independence. FWC reports exclusively to the Compensation Committee and does not provide any additional services to HLS or us. The Compensation Committee has discussed these considerations and has concluded that FWC is independent and that neither we nor HLS have any conflicts of interest with FWC.

Executive Committee

The Executive Committee has such authority as the Board may delegate to it from time to time.

Report of the Audit Committee for the Year Ended December 31, 2014

Management of Holly Logistic Services, L.L.C. is responsible for Holly Energy Partners, L.P.'s system of internal controls over financial reporting. The Audit Committee selected, and the Board approved, the selection of, Ernst & Young LLP as Holly Energy Partners, L.P.'s independent registered public accounting firm to audit the books, records and accounts of Holly Energy Partners, L.P. for the year ended December 31, 2014. Ernst & Young LLP is responsible for performing an independent audit of Holly Energy Partners, L.P.'s consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board and to issue a report thereon. The Audit Committee also is responsible for selecting, engaging and overseeing the work of the independent registered public accounting firm, which reports directly to the Audit Committee, and evaluating its qualifications and performance. Among other things, to fulfill its responsibilities, the Audit Committee:

- reviewed and discussed Holly Energy Partners, L.P.'s quarterly unaudited consolidated financial statements and its audited annual consolidated financial statements for the year ended December 31, 2014 with management and Ernst & Young LLP, including a discussion of the quality, not just the acceptability, of the accounting principles, the reasonableness of significant judgments and the clarity of disclosures in the financial statements, including those in management's discussion and analysis thereof;

- discussed with Ernst & Young LLP the matters required to be discussed by Auditing Standards No. 16, Communications with Audit Committees, as adopted by the Public Company Accounting Oversight Board;

- discussed with Ernst & Young LLP matters relating to its independence and received the written disclosures and letter from Ernst & Young required by applicable requirements of PCAOB regarding the independent accountant's communications with the Audit Committee concerning the firm's independence;

- discussed with Holly Energy Partners, L.P.'s internal auditors and Ernst & Young LLP the overall scope and plans for their respective audits (the Audit Committee meets with the internal auditors and Ernst & Young LLP, with and without management present, to discuss the results of their examinations, their evaluations of our internal controls and the overall quality of Holly Energy Partners, L.P.'s financial reporting); and

- considered whether Ernst & Young LLP's provision of non-audit services to Holly Energy Partners, L.P. is compatible with the auditor's independence

The Audit Committee charter requires the Audit Committee to approve in advance all audit and non-audit services to be provided by our independent registered public accounting firm. All fees for audit, audit-related and tax services as well as all other fees presented under Item 14 "Principal Accountant Fees and Services" were approved by the Audit Committee in accordance with its charter.

Based on the foregoing review and discussions and such other matters the Audit Committee deemed relevant and appropriate, the Audit Committee recommended to the Board that the audited consolidated financial statements of Holly Energy Partners, L.P. for the year ended December 31, 2014 be included in Holly Energy Partners, L.P.'s

Annual Report on Form 10-K for the year ended December 31, 2014 for filing with the SEC.

Members of the Audit Committee:
Jerry W. Pinkerton, Chairman
Charles M. Darling, IV
P. Dean Ridenour

Director Compensation

The Compensation Committee annually evaluates the compensation program for members of the Board who are not officers or employees of HLS or HFC ("non-employee directors"). In 2014, based on a recommendation from the Compensation Committee, the Board approved changes to the non-employee director compensation program, effective August 1, 2014. The components of non-employee director compensation prior to and after August 1, 2014 are described below. Directors who also serve as officers or employees of HLS or HFC do not receive additional compensation for serving on the Board.

	Effective Prior to August 1, 2014	Effective August 1, 2014
Annual cash retainer (payable in four quarterly installments)	$50,000	$60,000
Board meeting or committee meeting attended in person (also paid to non-members of committees who are invited to attend by such committee's chairman) (1)	$1,500	$1,500
Telephonic special board or committee meeting (2)	$1,000	$1,000
Each attended strategy meeting with HLS management	$1,500	$1,500
Annual equity retainer of restricted units under the Long-Term Incentive Plan	$75,000	$75,000
Special cash retainer for chairmen of committees and subcommittees (payable in four quarterly installments) (3)	$10,000	$10,000

(1) Upon submission of appropriate documentation, non-employee directors also are reimbursed for reasonable out-of-pocket expenses incurred in connection with attending Board or committee meetings.

(2) Prior to August 1, 2014, non-employee directors received $1,000 for telephonic special meetings that lasted over 30 minutes, and the Chairman of the Board and the chairman of each committee had authority to exercise his discretion as to whether the topics discussed at a telephonic special meeting of the Board or committee, as applicable, that lasted 30 minutes or less warranted a fee of $1,000. Effective August 1, 2014, non-employee directors receive $1,000 for all telephonic special meetings regardless of the length of the meeting.

(3) In connection with his retirement from HLS, the Compensation Committee approved a special retainer for Mr. Clifton for 2014, which is described in greater detail in footnote (2) to the Director Compensation Table below.

Annual Equity Awards

Non-employee directors receive an annual equity award grant under the Holly Energy Partners, L.P. Amended and Restated Long-Term Incentive Plan ("Long-Term Incentive Plan") in the form of restricted units having a fair market value of $75,000 on the date of grant, with the number of restricted units rounded up to the nearest whole unit in the case of fractional units. The fair market value of the grant is calculated based on the closing price of our common units on the day of grant (or the last business day prior to the date of grant if the date of grant occurs on a Saturday or Sunday). Continued service on the Board through the stated vesting date, which in most cases is approximately one year following the date of grant, is required in order for the restricted units to vest. Vesting of all unvested units will accelerate upon a change in control of HFC, HLS, HEP or HEP Logistics. In addition, vesting of unvested units will accelerate on a pro-rata basis upon the director's death, total and permanent disability or retirement. Directors are entitled to receive all distributions paid with respect to outstanding restricted units. The distributions are not subject to forfeiture. The directors also have a right to vote with respect to the restricted units.

At its regularly scheduled third quarter meeting in 2014, the Compensation Committee decided to change the timing of the annual equity award grants for non-employee directors. Specifically, the Compensation Committee determined that (a) annual restricted unit grants beginning in 2015 and later years will be made in the fourth quarter of each year, rather than in the third quarter of each year, and (b) annual restricted unit grants will vest on December 1 of the year following the year in which the grant is made, rather than on August 1 of that year, so that continued service on the Board for a full year following the date of grant of the award is required in order for the restricted units to become vested. As a result, for 2014 only, the non-employee directors received an annual equity award grant on August 1, 2014 in the form of restricted units having a fair market value of $100,000 on the date of grant (instead of the typical $75,000), which will vest in full on December 1, 2015, subject to continued service on the Board through that date. The additional $25,000 compensates the non-employee directors for the extended restricted period for the 2014 grant beyond the typical one-year period. The next annual equity award grant to the non-employee directors is scheduled to be made in the fourth quarter of 2015.

Non-Qualified Deferred Compensation

Non-employee directors are eligible to participate in the HollyFrontier Corporation Executive Nonqualified Deferred Compensation Plan, which is not tax-qualified under Section 401 of the Internal Revenue Code and allows participants to defer receipt of certain compensation (the “NQDC Plan”). The NQDC Plan allows non-employee directors the ability to defer up to 100% of their cash retainers and meeting fees for a calendar year. Participating directors have full discretion over how their contributions to the NQDC Plan are invested among the offered investment options. Earnings on amounts contributed to the NQDC Plan are calculated in the same manner and at the same rate as earnings on actual investments. Neither HLS nor HFC subsidizes a participant’s earnings under the NQDC Plan.

Mr. Pinkerton was the only non-employee director that participated in the NQDC Plan in 2014. During 2014, no above market or preferential earnings were paid to Mr. Pinkerton under the NQDC Plan and, therefore, none of the earnings received by Mr. Pinkerton during 2014 are included in the Director Compensation Table below. For additional information on the NQDC Plan, see “Compensation Discussion and Analysis-Overview of 2014 Executive Compensation Components and Decisions-Retirement and Benefit Plans-Deferred Compensation Plan” and the narrative preceding the “Nonqualified Deferred Compensation Table.”

Unit Ownership and Retention Policy for Directors

Effective October 2013, our directors became subject to a new unit ownership and retention policy. Pursuant to the policy, each director is required to hold during service on the Board common units equal in value to at least two times the annual equity retainer paid to non-employee directors. For 2014, each non-employee director was required to hold common units equal in value to $200,000. Each subject director is required to meet the applicable requirements within five years of first being subject to the policy. Mr. Clifton first became subject to the director unit ownership and retention policy upon his appointment as Chairman of the Board in a non-employee capacity, effective February 28, 2014.

Directors are also required to continuously own sufficient units to meet the unit ownership and retention requirements once attained. Until directors meet the requirements, they will be required to hold 25% of the units received from any equity award. If a director attains compliance with the policy and subsequently falls below the requirement because of a decrease in the price of our common units, the director will be deemed in compliance provided that the director retains the units then held.

As of December 31, 2014, all of our directors were in compliance with the unit ownership and retention policy.

Anti-Hedging and Anti-Pledging Policy

Members of the Board are subject to the HEP Insider Trading Policy, which, among other things, prohibits such directors from entering into short sales or hedging or pledging our common units and HFC common stock.

Director Compensation Table

The table below sets forth the compensation earned in 2014 by each of the non-employee directors of HLS:

Name (1)	Fees Earned or Paid in Cash (2)	Unit Awards (3)	All Other Compensation	Total
Matthew P. Clifton (4)	$154,494	$100,033	$ 69,637 (5)	$324,164
Charles M. Darling, IV	99,167	100,033	—	199,200

William J. Gray	86,167	100,033	32,231 (6)	218,431
Jerry W. Pinkerton	94,667	100,033	—	194,700
P. Dean Ridenour	77,167	100,033	—	177,200
William P. Stengel	96,167	100,033	—	196,200
James G. Townsend	80,167	100,033	—	180,200

(1) Mr. Jennings is not included in this table because he received no additional compensation for his service on the Board since, during 2014, Mr. Jennings was also an officer of HFC and HLS. The compensation paid by HFC to Mr. Jennings in 2014 will be shown in HFC's 2015 Proxy Statement. A portion of the compensation paid to Mr. Jennings by HFC is allocated to the services he performs for us in his capacity as an officer of HLS and is disclosed in the "Summary Compensation Table" below.

(2) For Mr. Clifton, includes a special retainer paid to him in 2014 of $125,000, less the amount of salary paid to him from January 1, 2014 until February 27, 2014, which salary amount is included in the “All Other Compensation” column of this table.

(3) Reflects the aggregate grant date fair value of restricted units granted to the non-employee directors on August 1, 2014, computed in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 718 (“FASB ASC Topic 718”), determined without regard to forfeitures. See Note 6 to our consolidated financial statements for the fiscal year ended December 31, 2014, for a discussion of the assumptions used in determining the FASB ASC Topic 718 grant date fair value of these awards.

On August 1, 2014, each of the non-employee directors received an award of 2,995 restricted units that vest on December 1, 2015, subject to continued service on the Board. As of December 31, 2014, these are the only restricted units held by our non-employee directors. Mr. Clifton also holds 48,948 performance units (assuming a maximum payout level of 200% at the time of vesting), which were granted to him while he served as Executive Chairman of HLS. For additional information regarding the annual restricted unit grants made on August 1, 2014 and certain changes to our annual equity award grant process for non-employee directors, please see “Annual Equity Retainer Awards” above.

(4) From January 1, 2014 until February 27, 2014, Mr. Clifton served as Executive Chairman of HLS. Effective February 28, 2014, Mr. Clifton retired from employment and was appointed Chairman of the Board in a non-employee capacity.

(5) During the period he served as Executive Chairman in 2014, Mr. Clifton received base salary payments for service as an employee. In addition, during that same period, the Compensation Committee approved cash payments to Mr. Clifton, as additional regular earnings, equal to amounts he would have received for service on the Board if he were a non-employee director. Thus, the amount reported in the “All Other Compensation” column represents (a) $27,404 earned by Mr. Clifton as salary in 2014 prior to his retirement on February 28, 2014, and (b) $15,500 earned as additional regular earnings for amounts he would have received for service on the Board if he were a non-employee director during the period from January 1, 2014 through February 27, 201