HOLLY ENERGY PARTNERS LP
Form 10-K
February 27, 2013
Table of Contentsril 19,

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, 2012
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 (State or other jurisdiction of incorporation or organization)	20-0833098 (I.R.S. Employer Identification No.)
2828 N. Harwood, Suite 1300 Dallas, Texas (Address of principal executive offices)	75201-1507 (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 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. ¨

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 $900 million on June 29, 2012, 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 15, 2013 was 56,782,048.

DOCUMENTS INCORPORATED BY REFERENCE: None

Table of Contentsril 19,

TABLE OF CONTENTS

Table of Contentsril 19,

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 successfully purchase and integrate additional operations in the future;
- 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.

Table of Contentsril 19,

INDEX TO DEFINED TERMS AND NAMES

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

Table of Contentsril 19,

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 44% interest in us, including the 2% general partner interest. Additionally, we own a 75% interest in UNEV Pipeline, LLC ("UNEV"), which owns a 400-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 960 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 10 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 400-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.

Table of Contentsril 19,

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 1,300,000 barrels, that are integrated with our refined product pipeline system that serves HFC's Navajo refinery;
- three refined product terminals (two of which are 50% owned), located in Burley and Boise, Idaho and Spokane, Washington, with an aggregate capacity of approximately 500,000 barrels, that serve third-party common carrier pipelines;
- one refined product terminal near Mountain Home, Idaho with a capacity of 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;
- a leased jet fuel terminal in Roswell, New Mexico;
- on-site crude oil tankage at HFC's Navajo, Woods Cross, Tulsa and Cheyenne refineries having an aggregate storage capacity of approximately 1,100,000 barrels;
- on-site refined and intermediate product tankage at HFC's Tulsa, Cheyenne and El Dorado refineries having an aggregate storage capacity of approximately 8,200,000 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 460,000 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 also will 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.

On November 29, 2012, we announced a two-for-one unit split, payable in the form of a common unit distribution for each issued and outstanding common unit. The unit distribution was paid January 16, 2013 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 periods presented.

2012 Acquisition

UNEV Pipeline Interest Acquisition

On July 12, 2012, we acquired from HFC a 75% interest in UNEV which owns a 400-mile, 12-inch refined products pipeline running from Woods Cross, Utah to Las Vegas, Nevada, product terminals near Cedar City, Utah and Las Vegas, Nevada and related assets. We paid consideration consisting of $260.9 million in cash and 2,059,800 of our common units (adjusted to reflect the unit split). As a result of the common units issued to HFC, HFC's ownership interest in us increased from 42% to 44% (including the 2% general partner interest). Also under the terms of the transaction, we issued to HFC a Class B unit comprising an 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 the next twelve consecutive quarterly periods 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 $25 million.

2011 Acquisition

Legacy Frontier Tankage and Terminal Transaction

On November 9, 2011, we acquired from HFC certain tankage, loading rack and crude receiving assets located at HFC's El Dorado and Cheyenne refineries. We paid non-cash consideration consisting of promissory notes with an aggregate principal amount of $150 million and 7,615,230 of our common units. In connection with the transaction, we entered into 15-year throughput agreements with HFC containing minimum annual revenue commitments to us of $48.3 million.

Table of Contentsril 19,

2010 Acquisitions

Tulsa East / Lovington Storage Asset Transaction

On March 31, 2010, we acquired from HFC certain storage assets for $88.6 million consisting of hydrocarbon storage tanks having approximately 2 million barrels of storage capacity, a rail loading rack and a truck unloading rack located at HFC’s Tulsa refinery east facility. Also, as part of this same transaction, we acquired HFC’s asphalt loading rack facility located at its Navajo refinery facility in Lovington, New Mexico for $4.4 million.

Agreements with HFC and Alon

We serve HFC’s refineries under long-term pipeline and terminal, tankage and throughput agreements expiring in 2019 through 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 the Federal Energy Regulatory Commission (“FERC”) index. Additionally, such agreements require HFC to reimburse us for certain costs. As of December 31, 2012, these agreements with HFC will result in minimum annualized payments to us of $217.2 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 also 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. In addition, we have a capacity lease agreement with Alon under which we lease Alon space on our Orla to El Paso pipeline for the shipment of up to 15,000 barrels of refined product per day. The terms under this agreement expire beginning in 2018 through 2022. As of December 31, 2012, these agreements with Alon will result in minimum annualized payments to us of $31.4 million.

A significant reduction in revenues under these agreements would 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 10 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 with HFC (the “Omnibus Agreement”), we pay HFC an annual administrative fee for the provision by HFC or its affiliates of various general and administrative services to us, currently $2.3 million. This fee includes expenses incurred by HFC and its affiliates 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 HLS who perform services for us 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 and its affiliates 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.

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 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 do not extend their useful life are charged to operating expenses as incurred.

Each year the HLS board of directors 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 2013 regular capital budget is comprised of $10.1 million for maintenance capital expenditures and $2.0 million for expansion capital expenditures exclusive of the projects discussed below. In addition to our capital budget, we may spend funds periodically to do capital upgrades of our assets where a customer reimburses us for such costs. These reimbursements would be required under contractual agreements and would generally benefit the customer over the remaining life of such agreements.

We recently have made certain modifications to our crude oil gathering and trunk line system that effectively have increased our ability to gather and transport an additional 10,000 barrels per day (“bpd”) of Delaware Basin crude oil in response to increased drilling activity in southeast New Mexico. We have a second project recently approved which consists of the reactivation and conversion to crude oil service of a 70-mile, 8-inch petroleum products pipeline owned by us. This project also includes the expansion and extension of several of our crude gathering systems and crude mainlines. Once in service, this system will be capable of transporting crude oil from southeast New Mexico to third-party common carrier pipelines in west Texas for further transport to major crude oil markets. This project is estimated to cost approximately $38.5 million and could be fully operational in late 2013.

We are also performing preliminary engineering, routing and cost estimates for two proposed new pipelines. The first proposed pipeline would be a new intrastate crude oil pipeline between Cushing, Oklahoma and HFC's Tulsa, Oklahoma refinery. The 50-mile line would provide safe and reliable transport of Cushing sourced domestic and Canadian crude oil to HFC's 125,000 BPD Tulsa facility. The pipeline would allow for a significant portion of crude oil transported to be heavy Canadian and sour crude oil. Crude oil processed at HFC's Tulsa facility is currently transported on pipelines owned by Sunoco Logistics and Magellan Pipeline Company. The second proposed pipeline would be a new 100-mile interstate petroleum products pipeline between the HFC's Cheyenne, Wyoming refinery and Denver, Colorado. The 52,000 BPD refinery, with its ability to process up to 35,000 BPD of heavy Canadian crude and its close proximity to growing domestic crude production, is a significant supplier of petroleum products to the Denver market. The project also will evaluate the construction of a new petroleum products terminal in North Denver or, alternatively, the routing of the new pipeline to existing third-party product terminals in the Denver area. This infrastructure addition would ensure safe and reliable transport of petroleum products from HFC's location-advantaged refinery to its largest market. Petroleum products produced at HFC's Cheyenne, Wyoming refinery are currently transported to Denver on the Rocky Mountain Pipeline’s products line owned by Plains All-American. We anticipate that we will be in a position to decide whether to proceed with these projects in the second quarter of 2013 when preliminary engineering and detailed project cost estimates are completed and if necessary shipper commitments can be secured.

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 existing cash generated by operations, the sale of additional limited partner common units, the issuance of debt securities and advances under our $550 million senior secured revolving credit facility expiring in June 2017 (the “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.
SAFETY AND MAINTENANCE
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 code or regulation. 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 conduct all cathodic protection work in accordance with National Association of Corrosion Engineers standards. We regularly monitor, test and record the effectiveness of these corrosion-inhibiting systems.
We monitor the structural integrity of selected 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 ensure that the pipelines that have the greatest risk potential receive the highest priority in being scheduled for inspections or pressure tests for integrity. Our inspection process complies with all Department of Transportation ("DOT") and Code of Federal Regulations ("CFR") 49 CFR Part 195 requirements.

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, state, and local laws; the regulations and standards prescribed by the American Petroleum Institute, the DOT; 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 also are 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 twelve 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 non-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.

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.

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.

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.

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, 2012, we have an accrual of $3.0 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, nevertheless, have the potential to substantially affect our business.

Table of Contentsril 19,

EMPLOYEES

Neither we nor our general partner has employees. Direct support for our operations is provided by HLS, which employs 232 people. We reimburse HFC for direct expenses that HFC or its affiliates incurs on our behalf for the employees of HLS. HLS considers its employee relations to be good.

Item 1A. Risk Factors

Investing in us involves a degree of risk, including the risks described below. 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 be affected also by economic, financial, competitive, and regulatory factors that are beyond our control. Because the cash we generate from operations will fluctuate from quarter to quarter, we may not be able to pay quarterly distributions at the current level for each quarter or to increase our quarterly distributions in the future.

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, 2012, HFC accounted for 79% of the revenues of our petroleum product and crude pipelines and 92% 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 curtailing of production at the Navajo refinery could, by reducing throughput in our pipelines and terminals, result in our realizing materially lower levels of revenues and cash flow for the duration of the shutdown. For the year ended December 31, 2012, production from the Navajo refinery accounted for 82% of the throughput volumes transported by our refined product and crude pipelines. The Navajo refinery also received 100% 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:

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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 or environmental proceedings or other litigation that compel the cessation 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:

Table of Contentsril 19,

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 magnitude of 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; is responsible for all related costs; and 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 substantial portion of our revenues; if those revenues were significantly reduced, there would be a material adverse effect on our results of operations.

For the year ended December 31, 2012, Alon accounted for 11% 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.
A decline in production at Alon's Big Spring refinery would reduce materially the volume of refined products we transport and terminal for Alon and, as a result, our revenues would 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 factors for the Navajo refinery.

The magnitude of 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, 2012, the principal amount of our total outstanding debt was $871 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 indentures for our 8.25% senior notes due 2018 and our 6.50% senior notes due 2020 (collectively, the “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.

Table of Contentsril 19,

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 prevailing 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 impair materially 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 assure you 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 2015 and $171 million prior to 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. Moreover, without adequate funding, we may be unable to execute our growth strategy, complete future acquisitions or construction projects, take advantage of other business opportunities or respond to competitive pressures, any of which 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.

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 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, 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. Our inability to execute our growth strategy may materially, adversely affect our ability to maintain or pay higher distributions in the future.

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 these and other 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 utilize 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 have agreed to indemnify us, subject to certain limitations, for (1) certain pre-closing environmental liabilities discovered within specified time periods after the date of the applicable acquisition, (2) certain matters arising from the pre-closing ownership and operation of assets, and (3) ongoing remediation related to the assets. Our 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 on the pipeline from the West Coast to Phoenix. 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 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, or 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. 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 current 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.

Meeting the requirements of evolving environmental, health and safety laws and regulations, including those related to climate change, could 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, HFC and Alon 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. Future developments in federal laws and regulations governing environmental, health and safety and energy matters are especially difficult to predict.

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 require HFC's and Alon's refineries to 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. 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.

Table of Contentsril 19,

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues and potentially the adoption of new regulatory requirements for existing pipelines. In addition, the Pipeline and Hazardous Materials Safety Administration of the U.S. Department of Transportation has published an advanced notice of proposed rulemaking to solicit comments on the need for changes to its safety regulations, including whether to revise the integrity management requirements and add new regulations governing the safety of gathering lines. Such legislative and regulatory changes could have a material effect on our operations through more stringent and comprehensive safety regulations and higher penalties for the violation of those regulations.

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, there can be no assurance that a system failure or data security breach will not 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 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 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 equipment or life 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.

Table of Contentsril 19,

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. With 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 those considered to be sudden and accidental. Our business interruption insurance covers only certain lost revenues arising from physical damage to our facilities and HFC and Alon 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 insure the quality and purity of the products loaded at our loading racks. If our quality control measures were to 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.

If our assumptions concerning population growth are inaccurate or if HFC's growth strategy is not successful, our ability to grow may be adversely affected.

Our growth strategy is dependent upon:

- the accuracy of our assumption that many of the markets that we currently serve or have plans to serve in the Southwestern, Rocky Mountain and Mid-Continent regions of the United States will experience population growth that is higher than the national average; and
- the willingness and ability of HFC to capture a share of this additional demand in its existing markets and to identify and penetrate new markets in the Southwestern, Rocky Mountain and Mid-Continent regions of the United States.

If our assumptions about growth in 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. Furthermore, HFC is under no obligation to pursue a growth strategy. If HFC chooses not to gain, or is unable to gain additional customers in new or existing markets, our growth strategy would be adversely affected.

Moreover, HFC may not make acquisitions that would provide acquisition opportunities to us; or, if those opportunities arise, they may not be on terms attractive to us or on terms that allow us to obtain appropriate financing.

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. If the FERC's petroleum pipeline rate-making methodology changes, the new methodology could result in tariffs that generate lower revenues and cash flow. 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. In addition, changes in the index might not be large enough to fully reflect actual increases in our costs. The FERC's 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 as far back as 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. These agreements do not prevent other current or future shippers from challenging 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 not known at this time. 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 may affect our operations in unpredictable ways, including disruptions of crude oil supplies and markets for refined products, and the possibility that infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror.

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 credit ratings and risk profile, and that of our general partner, 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

Table of Contentsril 19,

access capital markets at attractive rates, and could result in an increase in our borrowing costs, a reduced level of capital expenditures and an impact on 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 of any future acquisitions 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. For example, in 2012 we completed the UNEV pipeline asset acquisition. Acquisitions may require substantial capital or the incurrence of substantial indebtedness. Our capitalization and results of operations may change significantly as a result of the acquisitions we recently completed or as a result of 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, including the assets we acquired in 2012. 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 affected materially and adversely.

Delays or cost increases related to capital spending programs involving construction of new facilities (or improvements and repairs to our existing facilities) could affect adversely 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 facilities are located. Our operations could be disrupted if we were to lose or were unable to renew existing rights-of-way.

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

Our business may suffer due to a change in the composition of our Board of Directors, or if any of our key senior executives or other key employees discontinue employment with HLS, who provide services to us. Furthermore, a shortage of skilled labor or disruptions in HLS's labor force 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. 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.

As of December 31, 2012, approximately 17% of HLS's employees were represented by labor unions under collective bargaining agreements with various expiration dates. We 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 strike or work stoppage in the future, and any work stoppage could negatively affect our results of operations and financial condition.

Many of our officers also allocate time to our general partner and its affiliates.

Our general partner shares officers and administrative personnel with HFC to operate both our business and HFC's business. Our general partners' officers, several of whom also are officers of HFC, will allocate the time they and the other employees of HFC spend on our behalf and on behalf of HFC. 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.

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 42% limited partner interest in us and owns and controls 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;
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- 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 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 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.

Table of Contentsril 19,

Under our Omnibus Agreement, we are currently obligated to pay HFC an administrative fee of $2.3 million per year for the provision by HFC or its affiliates of various general and administrative services for our benefit. We can provide no 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 properly 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 Holly Logistic Services, L.L.C. 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, for 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, for 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 our general partner's general partner and have no right to elect our general partner or the board of directors of our general partner's general partner on an annual or other continuing basis. The board of directors of our general partner's general partner is chosen by the members of our general partner's general partner. Furthermore, 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 or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to 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 taken 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.

Table of Contentsril 19,

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;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- 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 among us, HFC and our general partner, 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 may cause us to borrow funds in order to make cash distributions, even where the purpose or effect of the borrowing benefits our general partner or its affiliates.

In some instances, our general partner may cause us to borrow funds from affiliates of HFC or from third parties in order to permit the payment of cash distributions. These borrowings are permitted even if the purpose and effect of the borrowing is to enable us to make incentive distributions.

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, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As 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 24,255,030 of our common units, which is approximately 42% 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, as a result of legislative changes, we were to become subject to additional amounts of entity-level taxation for federal or state tax purposes, then our cash available for distribution to unitholders would be substantially reduced.

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

Despite the fact that we are organized as a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe, based upon our current operations, that we will be so treated, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%. Under current law, 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.

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, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Currently, 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 expectation for certain publicly traded partnerships to be treated as partnerships 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, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

Unitholders will be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Because our unitholders will generally be treated as partners to whom we allocate taxable income, which could be different in amount than the cash we distribute, they will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability resulting from 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 depreciation and deductions and certain other items. 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 (known as IRAs), Keogh Plans and other retirement plans, regulated investment companies and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be “unrelated business taxable income” and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal 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 we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from 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 is no tax concept 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, 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.

Table of Contentsril 19,

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 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,				
	2012	2011	2010	2009	2008
Volumes transported for (bpd):					
HFC	405,718	345,990	324,382	295,039	253,484
Third parties[1]	63,152	52,361	38,910	43,709	22,756
Total	468,870	398,351	363,292	338,748	276,240
Total barrels in thousands (“mbbls”)[1]	171,606	145,398	132,602	123,643	101,104

(1) We sold our 70% interest in Rio Grande on December 1, 2009, therefore the Rio Grande volumes have been excluded.

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	105	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	36	5,300	
Woods Cross, UT	10/8	8	70,000	
Woods Cross, UT to Las Vegas, NV	12	400	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	96,000	
Tulsa, OK(5)	8/10/12	10		(5)
Crude Pipelines:				
Lovington / Artesia, New Mexico	Various	861	31,000	
Roadrunner Pipeline	16	65	62,400	
Beeson Pipeline	8	37	35,000	
Woods Cross, Utah	12	4	40,000	

(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 pipe capacities with 3 gas pipes with capacities of 10 million standard cubic feet per day ("MMSCFD"), 22MMSCFD, and 10MMSCFD and 2 liquid pipes with capacities of 45,000 BPD and 60,000 BPD.

HFC shipped an aggregate of 63% of the petroleum products transported on our refined product pipelines and 100% of the petroleum products transported on our intermediate pipelines and crude oil pipelines in 2012. These pipelines transported 90% of the light refined products produced by HFC's Navajo refinery in 2012.

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, 124-mile segment from Orla to outside El Paso, Texas; and
- an 8-inch, 8-mile segment from outside El Paso to our El Paso terminal.

Table of Contentsril 19,

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 $556,000 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 our terminal in Bloomfield. At our Bloomfield terminal, volumes shipped on this pipeline are transported to other markets in the Four Corners area via tanker truck. 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 100 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 85 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 36-mile, 4-inch diameter Artesia to Roswell refined product pipeline delivers jet fuel only to tanks located at our jet fuel terminal in Roswell. HFC is the only shipper on this pipeline.

Woods Cross, Utah refined product pipelines

The Woods Cross refined product pipelines consist of three pipeline segments. The Woods Cross to Pioneer terminal segment consists of 2 miles of 8-inch pipeline, which is used for product shipments to and through the Pioneer terminal. 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 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 Chevron's North Salt Lake pumping station. HFC is the only shipper on these pipelines.

UNEV refined product pipeline

The 400-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.

Table of Contentsril 19,

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. HFC is the only shipper on this pipeline.

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 850 miles of 4-inch, 6-inch and 8-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.

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 65 miles of 16-inch pipeline. This pipeline is used for the shipment of crude oil from Cushing to the Navajo refinery Lovington facility.

Beeson Pipeline
The Beeson crude oil pipeline delivers crude oil to the Navajo refinery Lovington facility. It was constructed in 2009 and consists of 37 miles of 8-inch pipeline. This pipeline ships crude oil from our crude oil gathering system to the Navajo refinery Lovington facility for processing.

Woods Cross, Utah crude oil pipeline
This 4-mile, 12-inch pipeline is used for the shipment of crude oil from Chevron Pipeline’s North Salt Lake City station to the Woods Cross refinery.

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.

Table of Contentsril 19,

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,				
	2012	2011	2010	2009	2008
Refined products terminalled for (bpd):					
HFC	271,549	193,645	178,903	114,431	109,539
Third parties	53,456	44,454	39,568	42,206	32,737
Total	325,005	238,099	218,471	156,637	142,276
Total (mbbls)	118,952	86,906	79,742	57,173	52,073

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	747,000	20	Pipeline/rail	Truck/Pipeline
Moriarty, NM	189,000	9	Pipeline	Truck
Bloomfield, NM	193,000	7	Pipeline	Truck
Tucson, AZ(1)	176,000	9	Pipeline	Truck
Mountain Home, ID(2)	120,000	3	Pipeline	Pipeline
Boise, ID(3)	111,000	9	Pipeline	Pipeline
Burley, ID(3)	70,000	7	Pipeline	Truck
Spokane, WA	333,000	32	Pipeline/Rail	Truck
Abilene, TX	156,100	6	Pipeline	Truck/Pipeline
Wichita Falls, TX	220,000	11	Pipeline	Truck/Pipeline
Las Vegas, NV	267,000	9	Pipeline/Truck	Truck
Cedar City, UT	194,000	7	Pipeline/Rail/Truck	Truck
Roswell, NM (2)	25,000	1	Pipeline	Truck
Orla tank farm	135,000	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	25,000	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	2,961,100			

(1) The underlying ground at the Tucson terminal is leased.
(2) Handles only jet fuel.
(3) We have a 50% ownership interest in these terminals. The capacity and throughput information represents the proportionate share of capacity and throughput attributable to our ownership interest.

Table of Contentsril 19,

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 90% of the volumes at this terminal. We also receive product from the Big Spring refinery that accounted for 10% of the volumes at this terminal in 2012. 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 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.

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 Chevron’s 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.

Boise Terminal
We and Sinclair each own a 50% interest in the Boise terminal. Sinclair is the operator of the terminal. The Boise terminal receives light refined products from HFC and Sinclair shipped through Chevron’s pipeline originating in Salt Lake City, Utah. The Woods Cross refinery, as well as other refineries in the Salt Lake City area, and Pioneer Pipeline Co.’s terminal in Salt Lake City are connected to the Chevron pipeline. All loading of products out of the Boise terminal is conducted at Chevron’s loading rack, which is connected to the Boise terminal by pipeline. HFC and Sinclair are the only customers at this terminal.

Burley Terminal
We and Sinclair each own a 50% interest in the Burley terminal. Sinclair is the operator of the terminal. The Burley terminal receives product from HFC and Sinclair shipped through Chevron’s pipeline originating in Salt Lake City, Utah. Refined products received at this terminal are sold locally, via the truck rack. HFC and Sinclair are the only customers at this terminal.

Spokane Terminal
This terminal is connected to the Woods Cross refinery via a Chevron common carrier pipeline. The Spokane terminal also is supplied by Chevron and Yellowstone pipelines and 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 2012. 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 2012. 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.

Table of Contentsril 19,

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 only 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 only customers at this terminal.

Roswell Terminal
This terminal receives jet fuel from the Navajo refinery for further transport to Cannon Air Force Base and to Albuquerque, New Mexico. We lease this terminal under an agreement that expires in September 2016.

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 2012. 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 racks that load refined products and lube oil produced at the refinery onto rail car and a truck rack that loads lube oil onto 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 9,300,000 barrels of storage.

Table of Contentsril 19,

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	166,000	Crude oil	2
Lovington, NM	267,000	Crude oil	2
Woods Cross, UT	180,000	Crude oil	3
Tulsa, OK	3,171,600	Crude oil and refined product	57
Cheyenne, WY	1,842,000	Refined and intermediate product	58
El Dorado, KS	3,702,400	Refined and intermediate product	89
Total	9,329,000		

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.

Table of Contentsril 19,

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
2012				
Fourth quarter	$34.41	$30.19	$0.470	6,938,000
Third quarter	$36.98	$28.56	$0.463	6,420,200
Second quarter	$31.44	$26.12	$0.455	5,298,000
First quarter	$31.88	$26.64	$0.448	6,704,400
2011				
Fourth quarter	$29.98	$23.65	$0.443	6,609,800
Third quarter	$27.51	$22.70	$0.438	4,050,800
Second quarter	$29.46	$24.28	$0.433	5,781,800
First quarter	$30.53	$25.06	$0.428	4,675,200

On November 29, 2012, we announced a two-for-one unit split, payable in the form of a common unit distribution for each issued and outstanding common unit. The unit distribution was paid January 16, 2013 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 periods presented.

The cash distribution for the fourth quarter of 2012 was declared on January 24, 2013 and is payable on February 14, 2013 to all unitholders of record on February 4, 2013.

As of February 13, 2013, we had approximately 14,400 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%

Table of Contentsril 19,

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,				
	2012	2011[1]	2010[1]	2009[1]	2008[1]
	(In thousands, except per unit data)				
Statement of Income Data:					
Revenues	$292,560	$214,268	$182,137	$146,612	$109,169
Operating costs and expenses					
Operations (exclusive of depreciation and amortization)	89,242	64,521	54,946	44,668	39,095
Depreciation and amortization	57,461	36,958	31,363	27,982	22,615
General and administrative	7,594	6,576	7,719	7,586	6,380
	154,297	108,055	94,028	80,236	68,090
Operating income	138,263	106,213	88,109	66,376	41,079
Equity in earnings of SLC Pipeline	3,364	2,552	2,393	1,919	—
SLC Pipeline acquisition costs	—	—	—	(2,500)	—
Interest income	—	—	7	11	118
Interest expense	(47,182)	(35,959)	(34,001)	(21,501)	(21,763)
Loss on early extinguishment of debt	(2,979)	—	—	—	—
Other income	10	17	17	67	1,026
	(46,787)	(33,390)	(31,584)	(22,004)	(20,619)
Income from continuing operations before income taxes	91,476	72,823	56,525	44,372	20,460
State income tax	(371)	(234)	(296)	(20)	(270)
Income from continuing operations	91,105	72,589	56,229	44,352	20,190
Add net loss attributable to Predecessor	4,200	6,351	70	1,411	379
Noncontrolling interest	(1,153)	859	24	471	127
Income from continuing operations attributable to Holly Energy Partners	94,152	79,799	56,323	46,234	20,696
Income from discontinued operations, net of noncontrolling interest[2]	—	—	—	19,780	4,671
Net income attributable to Holly Energy Partners	94,152	79,799	56,323	66,014	25,367
Less general partner interest in net income, including incentive distributions[3]	22,450	16,806	12,084	7,947	3,913
Limited partners' interest in net income	$71,702	$62,993	$44,239	$58,067	$21,454
Limited partners' per unit interest in net income – basic and diluted[3]	$1.29	$1.38	$1.00	$1.59	$0.66
Distributions per limited partner unit	$1.84	$1.74	$1.66	$1.58	$1.50
Other Financial Data:					
Cash flows from operating activities	$161,411	$99,042	$104,736	$68,503	$64,015
Cash flows from investing activities	$(42,861)	$(206,309)	$(142,051)	$(198,684)	$(298,557)
Cash flows from financing activities	$(119,682)	$105,584	$35,856	$131,023	$218,564
EBITDA[4]	$194,242	$149,766	$122,089	$100,707	$70,195
Distributable cash flow[5]	$153,125	$100,295	$91,054	$72,213	$60,365
Maintenance capital expenditures[5]	$5,649	$5,415	$4,487	$3,595	$3,133
Expansion capital expenditures	37,212	200,894	137,442	201,454	295,460

Total capital expenditures	$42,861	$206,309	$141,929	$205,049	$298,593
Balance Sheet Data (at period end):					
Net property, plant and equipment	$960,535	$960,499	$683,793	$553,233	$363,038
Total assets	$1,394,110	$1,399,196	$913,263	$779,035	$549,762
Long-term debt(6)	$864,674	$605,888	$491,648	$390,827	$355,793
Total liabilities	$927,351	$661,518	$548,402	$425,633	$434,821
Total equity(7)	$452,856	$737,678	$364,861	$353,402	$114,941

(1) The amounts presented have been restated from those we previously reported for the respective periods. See Note 2 in Notes to Consolidated Financial Statements included in Item 8 for a discussion of these revisions.

Table of Contentsril 19,

(2) On December 1, 2009, we sold our 70% interest in Rio Grande. Results of operations of Rio Grande and the $14.5 million gain on the sale are presented in discontinued operations.

(3) 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.

(4) Earnings before interest, taxes, depreciation and amortization ("EBITDA") is calculated as net income plus (i) interest expense net of interest income, (ii) state income tax and (iii) depreciation and amortization. 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.

Set forth below is our calculation of EBITDA.

	Years Ended December 31,				
	2012	2011[(1)]	2010[(1)] presented have been restated from those we previously reported for the respective periods. See Note 2 in Notes to Consolidated Financial Statements included in Item 8 for a discussion of these revisions.	2009[(1)]	2008[(1)]
	(In thousands)				
Income from continuing operations attributable to HEP	$94,152	$79,799	$ 56,323	$46,234	$20,696
Add (subtract):					
Interest expense	40,141	34,706	30,453	20,620	18,479
Amortization of discount and deferred debt issuance costs	1,946	1,212	1,008	706	1,002
Loss on early extinguishment of debt	2,979	—	—	—	—
Increase in interest expense – non-cash charges attributable to interest rate swaps and swap settlement costs	5,095	41	2,540	175	2,282

Interest income	—	—	(7)	(11)	(118)
State income tax	371	234	296	20	270
Depreciation and amortization	57,461	36,958	31,363	27,982	22,615
Predecessor depreciation and amortization	(7,903)	(3,184)	113	(1,268)	(678)
EBITDA from discontinued operations (excludes gain on sale of Rio Grande in 2009)	—	—	—	6,249	5,647
EBITDA	$194,242	$149,766	$ 122,089	$100,707	$70,195

(5) 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 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. It also 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.

Table of Contentsril 19,

Set forth below is our calculation of distributable cash flow.

	Years Ended December 31,				
	2012	2011(1)	2010(1)	2009(1)	2008(1)
	(In thousands)				
Income from continuing operations attributable to HEP	$94,152	$79,799	$56,323	$46,234	$20,696
Add (subtract):					
Depreciation and amortization	57,461	36,958	31,363	27,982	22,615
Predecessor depreciation and amortization	(7,903)	(3,184)	113	(1,268)	(678)
Amortization of discount and deferred debt issuance costs	1,946	1,212	1,008	706	1,002
Increase in interest expense – non-cash charges attributable to interest rate swaps	5,095	41	2,540	175	2,282
Loss on early extinguishment of debt	2,979	—	—	—	—
Increase (decrease) in deferred revenue	462	(6,405)	2,035	(7,256)	11,958
Maintenance capital expenditures*	(5,649)	(5,415)	(4,487)	(3,595)	(3,133)
Crude revenue settlement	3,670	(4,588)	—	—	—
Distributable cash flow from discontinued operations (excludes gain on sale of Rio Grande in 2009)	—	—	—	6,183	5,623
SLC Pipeline acquisition costs**	—	—	—	2,500	—
Other non-cash adjustments	912	1,877	2,159	552	—
Distributable cash flow	$153,125	$100,295	$91,054	$72,213	$60,365

* 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.

** Under accounting standards, we were required to expense rather than capitalize certain acquisition costs of $2.5 million associated with our joint venture agreement with Plains that closed in March 2009. These costs directly relate to our interest in the new joint venture pipeline and are similar to expansion capital expenditures; accordingly, we have added back these costs to arrive at distributable cash flow.

(6) Includes $421 million, $200 million, $159 million, $206 million and $171 million in Credit Agreement advances that were classified as long-term debt at December 31, 2012, 2011, 2010, 2009 and 2008, respectively.

(7) 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 $305.6 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.

Table of Contentsril 19,

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 the refining and marketing operations of HFC in the Mid-Continent, Southwest and Rocky Mountain regions of the United States. At December 31, 2012, HFC owned a 44% interest in us including the 2% general partnership interest. We also own and operate refined product pipelines and terminals, located primarily in Texas, that service Alon's refinery in Big Spring, Texas. Additionally, we own a 75% interest in UNEV, the owner of a pipeline running from 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 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 November 29, 2012, we announced a two-for-one unit split, payable in the form of a common unit distribution for each issued and outstanding common unit. The unit distribution was paid January 16, 2013 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 periods presented.

UNEV Pipeline Interest Acquisition
On July 12, 2012, we acquired HFC's 75% interest in UNEV. We paid consideration consisting of $260.9 million in cash and 2,059,800 of our common units (adjusted to reflect the unit split). As a result of the common units issued to HFC, HFC's ownership interest in us increased from 42% to 44% (including the 2% general partner interest). Also under the terms of the transaction, we issued to HFC a Class B unit comprising an 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 the next twelve consecutive quarterly periods and up to an additional four quarters in certain circumstances.

Legacy Frontier Pipeline and Tankage Asset Transaction
On November 9, 2011, we acquired from HFC certain tankage, loading rack and crude receiving assets located at HFC's El Dorado and Cheyenne refineries. We paid non-cash consideration consisting of promissory notes with an aggregate principal amount of $150 million and 7,615,230 of our common units. In connection with the transaction, we entered into 15-year throughput agreements with HFC containing minimum annual revenue commitments to us of $48.3 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 PPI or FERC index. As of December 31, 2012, these agreements with HFC will result in minimum annualized payments to us of $217.2 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 also 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. The terms under this agreement expire beginning in 2018 through 2022. 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. As of December 31, 2012, these agreements with Alon will result in minimum annualized payments to us of $31.4 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, currently $2.3 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 HLS who perform services for us or the cost of their employee benefits, which are separately charged to us by HFC. We also reimburse HFC and its affiliates for direct expenses they incur on our behalf.

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, 2012, 2011 and 2010.

	Year Ended December 31,		Change from
	2012	2011[1]	2011
	(In thousands, except per unit data)		
Revenues			
Pipelines:			
Affiliates—refined product pipelines	$67,682	$46,649	$21,033
Affiliates—intermediate pipelines	28,540	21,948	6,592
Affiliates—crude pipelines	45,888	47,542	(1,654)
	142,110	116,139	25,971
Third parties—refined product pipelines	37,521	38,216	(695)
	179,631	154,355	25,276
Terminals, tanks and loading racks:			
Affiliates	103,472	52,122	51,350
Third parties	9,457	7,791	1,666
	112,929	59,913	53,016
Total revenues	292,560	214,268	78,292
Operating costs and expenses			
Operations (exclusive of depreciation and amortization)	89,242	64,521	24,721
Depreciation and amortization	57,461	36,958	20,503
General and administrative	7,594	6,576	1,018
	154,297	108,055	46,242
Operating income	138,263	106,213	32,050
Equity in earnings of SLC Pipeline	3,364	2,552	812
Interest expense, including amortization	(47,182)	(35,959)	(11,223)
Loss on early extinguishment of debt	(2,979)	—	(2,979)
Other	10	17	(7)
	(46,787)	(33,390)	(13,397)
Income before income taxes	91,476	72,823	18,653
State income tax	(371)	(234)	(137)
Net income	91,105	72,589	18,516
Allocation of net loss attributable to Predecessors	4,200	6,351	(2,151)
Allocation of net loss (income) attributable to noncontrolling interests	(1,153)	859	(2,012)
Net income attributable to Holly Energy Partners	94,152	79,799	14,353
General partner interest in net income, including incentive distributions [2]	(22,450)	(16,806)	(5,644)
Limited partners' interest in net income	$71,702	$62,993	$8,709
Limited partners' earnings per unit—basic and diluted[2]	$1.29	$1.38	$(0.09)
Weighted average limited partners' units outstanding	55,696	45,672	10,024
EBITDA [3]	$194,242	$149,766	$44,476
Distributable cash flow [4]	$153,125	$100,295	$52,830
Volumes (bpd)			
Pipelines:			
Affiliates—refined product pipelines	107,509	90,782	16,727

Affiliates—intermediate pipelines	127,169	93,419	33,750
Affiliates—crude pipelines	171,040	161,789	9,251
	405,718	345,990	59,728
Third parties—refined product pipelines	63,152	52,361	10,791
	468,870	398,351	70,519
Terminals and loading racks:			
Affiliates	271,549	193,645	77,904
Third parties	53,456	44,454	9,002
	325,005	238,099	86,906
Total for pipelines and terminal assets (bpd)	793,875	636,450	157,425

Table of Contentsril 19,

	Years Ended December 31, 2011[1]	2010[1]	Change from 2010
	(In thousands, except per unit data)		
Revenues			
Pipelines:			
Affiliates—refined product pipelines	$46,649	$48,458	$(1,809)
Affiliates—intermediate pipelines	21,948	20,998	950
Affiliates—crude pipelines	47,542	38,932	8,610
	116,139	108,388	7,751
Third parties—refined product pipelines	38,216	27,962	10,254
	154,355	136,350	18,005
Terminals, tanks and loading racks:			
Affiliates	52,122	37,979	14,143
Third parties	7,791	7,808	(17)
	59,913	45,787	14,126
Total revenues	214,268	182,137	32,131
Operating costs and expenses			
Operations (exclusive of depreciation and amortization)	64,521	54,946	9,575
Depreciation and amortization	36,958	31,363	5,595
General and administrative	6,576	7,719	(1,143)
	108,055	94,028	14,027
Operating income	106,213	88,109	18,104
Equity in earnings of SLC Pipeline	2,552	2,393	159
Interest expense, including amortization	(35,959)	(33,994)	(1,965)
Other expense	17	17	—
	(33,390)	(31,584)	(1,806)
Income before income taxes	72,823	56,525	16,298
State income tax	(234)	(296)	62
Net income	72,589	56,229	16,360
Allocation of net loss attributable to Predecessors	6,351	70	6,281
Allocation of net loss attributable to noncontrolling interests	859	24	835
Net income attributable to Holly Energy Partners	79,799	56,323	23,476
General partner interest in net income, including incentive distributions [2]	(16,806)	(12,084)	(4,722)
Limited partners' interest in net income	$62,993	$44,239	$18,754
Limited partners' earnings per unit—basic and diluted[2]	$1.38	$1.00	$0.38
Weighted average limited partners' units outstanding	45,672	44,157	1,515
EBITDA [3]	$149,766	$122,089	$27,677
Distributable cash flow [4]	$100,295	$91,054	$9,241
Volumes (bpd)			
Pipelines:			
Affiliates—refined product pipelines	90,782	96,094	(5,312)
Affiliates—intermediate pipelines	93,419	84,277	9,142
Affiliates—crude pipelines	161,789	144,011	17,778
	345,990	324,382	21,608
Third parties—refined product pipelines	52,361	38,910	13,451
	398,351	363,292	35,059
Terminals and loading racks:			

Affiliates	193,645	178,903	14,742
Third parties	44,454	39,568	4,886
	238,099	218,471	19,628
Total for pipelines and terminal assets (bpd)	636,450	581,763	54,687

(1) The amounts presented above have been restated from those we previously reported for the respective periods. See Note 2 in Notes to Consolidated Financial Statements included in Item 8 for a discussion of these revisions.

Table of Contentsril 19,

(2) 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.

(3) EBITDA is calculated as net income plus (i) interest expense, net of interest income, (ii) state income tax and (iii) depreciation and amortization. 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."

(4) 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 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. It is also 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, 2012 Compared with Year Ended December 31, 2011

Summary
Net income attributable to HEP for the year ended December 31, 2012 was $94.2 million, a $14.4 million increase compared to the year ended December 31, 2011. This increase in earnings is due principally to increased pipeline shipments, earnings attributable to our November 2011 acquisition and annual tariff increases. These factors were offset partially by increased operating costs and expenses, higher interest expense and a loss on the early extinguishment of debt. Although net income attributable to HEP increased, limited partners' per unit interest in earnings decreased from $1.38 per unit in 2011 to $1.29 per unit in 2012. The principal factors causing the decrease in limited partners' per unit interest, relative to the overall net income attributable to HEP increase, were higher incentive distributions to the general partner and the UNEV acquisition not yet being accretive to earnings, although it was accretive to distributable cash flow.

Revenues for the year ended December 31, 2012 include the recognition of $4.0 million of prior shortfalls billed to shippers in 2011. Deficiency payments of $7.8 million associated with certain guaranteed shipping contracts were deferred during the year ended December 31, 2012. Such deferred revenue will be recognized in earnings either as payment for shipments in excess of guaranteed levels, if and to the extent the pipeline system will not have necessary capacity to provide for shipments in excess of guaranteed levels, or when shipping rights expire unused.

Revenues
Total revenues for the year ended December 31, 2012 were $292.6 million, a $78.3 million increase compared to the year ended December 31, 2011. This is due principally to increased pipeline shipments, revenues attributable to our

recent acquisitions and the effect of annual tariff increases partially offset by a $4.6 million decrease in previously deferred revenue realized under our guaranteed shipping contracts. Overall pipeline volumes were up 18% compared to the year ended December 31, 2011.

Revenues from our refined product pipelines were $105.2 million, an increase of $20.3 million compared to the year ended December 31, 2011. This includes $15.0 million in revenues attributable to UNEV pipeline throughputs which commenced initial start-up activities in December 2011 partially offset by a $5.4 million decrease in previously deferred revenue realized under our guaranteed shipping contracts. Volumes shipped on our refined product pipelines averaged 170.7 thousand barrels per day (“mbpd“) compared to 143.1 mbpd for 2011.

Revenues from our intermediate pipelines were $28.5 million, an increase of $6.6 million compared to the year ended December 31, 2011. This includes $3.4 million of increased revenues attributable to the Tulsa interconnect pipelines, which were placed in service in September 2011, and a $0.8 million increase in previously deferred revenue realized under our guaranteed shipping contracts. Volumes shipped on our intermediate pipelines averaged 127.2 mbpd compared to 93.4 mbpd for 2011.

Revenues from our crude pipelines were $45.9 million, a decrease of $1.7 million compared to the year ended December 31, 2011. Revenues for the year ended December 31, 2011 included $5.5 million attributable to a crude pipeline revenue settlement with HFC. Volumes shipped on our crude pipelines increased to an average of 171.0 mbpd compared to 161.8 mbpd for 2011.

Revenues from terminal, tankage and loading rack fees were $112.9 million, an increase of $53.0 million compared to year ended December 31, 2011. This increase is due principally to $45.4 million of increased revenues attributable to our terminal, tankage and loading racks serving HFC's El Dorado and Cheyenne refineries. Refined products terminalled in our facilities increased to an average of 325.0 mbpd compared to 238.1 mbpd for 2011.

Operations Expense

Operations expense for the year ended December 31, 2012 increased by $24.7 million compared to the year ended December 31, 2011. This increase is due principally to increased operating costs of $9.6 million and $5.2 million attributable to our recently acquired UNEV pipeline and assets serving HFC's El Dorado and Cheyenne refineries, respectively, higher throughput levels as well as year-over-year increases in property taxes, maintenance service and payroll costs.

Depreciation and Amortization

Depreciation and amortization for the year ended December 31, 2012 increased by $20.5 million compared to the year ended December 31, 2011. This increase is due principally to depreciation attributable to our recent acquisitions from HFC and capital projects. Also contributing were increases in asset abandonment charges related to tankage no longer in service.

General and Administrative

General and administrative costs for the year ended December 31, 2012 increased by $1.0 million compared to the year ended December 31, 2011 due to timing of professional fees related to recent acquisitions.

Equity in Earnings of SLC Pipeline

Our equity in earnings of the SLC Pipeline was $3.4 million and $2.6 million for the years ended December 31, 2012 and 2011.

Interest Expense

Interest expense for the year ended December 31, 2012 totaled $47.2 million, an increase of $11.2 million compared to the year ended December 31, 2011. This increase reflects interest on a year-over-year increase in debt levels. Our aggregate effective interest rate was 6.5% and 6.7% for the years ended December 31, 2012 and 2011, 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 for the year ended December 31, 2012. This charge relates 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.

State Income Tax

We recorded state income tax expense of $371,000 and $234,000 for the years ended December 31, 2012 and 2011 which is solely attributable to the Texas margin tax.

Results of Operations—Year Ended December 31, 2011 Compared with Year Ended December 31, 2010

Summary
Net income attributable to HEP for the year ended December 31, 2011 was $79.8 million, a $23.5 million increase compared to the year ended December 31, 2010. This increase in overall earnings is due principally to increased pipeline shipments, earnings attributable to our November 2011 asset acquisition and an increase in previously deferred revenue realized under our guaranteed shipping contracts. Also contributing to earnings was a settlement with HFC relating to a clarification of the appropriate charges for certain past deliveries into our crude pipeline system. These factors were offset partially by an overall increase in operating costs and expenses.

Revenues for the year ended December 31, 2011 include the recognition of $12.4 million of prior shortfalls billed to shippers in 2010. Deficiency payments of $4.0 million associated with certain guaranteed shipping contracts were deferred during the year ended December 31, 2011.

Revenues
Total revenues for the year ended December 31, 2011 were $214.3 million, a $32.1 million increase compared to the year ended December 31, 2010. This is due principally to an overall increase in pipeline shipments, revenues attributable to our November 2011 asset acquisitions, a $4 million increase in previously deferred revenue realized under our guaranteed shipping contracts, the effect of annual tariff increases and the HFC crude pipeline revenue settlement. Overall pipeline volumes were up 10% compared to the year ended December 31, 2010.

Certain related-party pipeline volumes were down during 2011 as a result of downtime at HFC's Navajo refinery following a plant-wide power outage in late January 2011 and the subsequent delay in restoring production to planned levels.

Revenues from our refined product pipelines were $84.9 million, an increase of $8.4 million compared to the year ended December 31, 2010. This is due to a $4.3 million increase in previously deferred revenue realized under our guaranteed shipping contracts and an increase in third-party refined product pipeline shipments. Volumes shipped on our refined product pipelines averaged 143.1 mbpd compared to 135.0 mbpd for the same period in 2010.

Revenues from our intermediate pipelines were $21.9 million, an increase of $1.0 million compared to the year ended December 31, 2010. This includes $0.8 million in revenues attributable to the Tulsa interconnect pipelines, and a $0.3 million decrease in previously deferred revenue realized under our guaranteed shipping contracts. Volumes shipped on our intermediate pipelines averaged 93.4 mbpd compared to 84.3 mbpd for the same period in 2010.

Revenues from our crude pipelines were $47.5 million, an increase of $8.6 million compared to the year ended December 31, 2010. This includes $5.5 million in revenues attributable to a crude pipeline revenue settlement with HFC. Volumes shipped on our crude pipelines increased to an average of 161.8 mbpd compared to 144.0 mbpd for the same period in 2010.

Revenues from terminal, tankage and loading rack fees were $59.9 million, an increase of $14.1 million compared to the year ended December 31, 2010. This increase is due principally to $7.1 million in revenues attributable to our terminal, tankage and loading racks serving HFC's El Dorado and Cheyenne refineries. Refined products terminalled in our facilities increased to an average of 238.1 mbpd compared to 218.5 mbpd for the same period last year.

Operations Expense
Operations expense for the year ended December 31, 2011 increased by $9.6 million compared to the year ended December 31, 2010. This increase is due principally to operating costs of $2.0 million and $3.8 million attributable to our recently acquired UNEV pipeline and assets serving HFC's El Dorado and Cheyenne refineries, respectively, as well as year-over-year increases in maintenance services and payroll costs. Additionally, in the year ended December 31, 2010, we recognized a charge for environmental remediation of $1.7 million.

Depreciation and Amortization
Depreciation and amortization for the year ended December 31, 2011 increased by $5.6 million compared to the year ended December 31, 2010. This increase is due principally to depreciation attributable to our acquisitions from HFC and capital projects.

General and Administrative
General and administrative costs for the year ended December 31, 2011 decreased by $1.1 million compared to the year ended December 31, 2010 due to lower professional fees and services.

Equity in Earnings of SLC Pipeline

Our equity in earnings of the SLC Pipeline was $2.6 million and $2.4 million for the years ended December 31, 2011 and 2010.

Interest Expense

Interest expense for the year ended December 31, 2011 totaled $36.0 million, an increase of $2.0 million compared to the year ended December 31, 2010. This increase reflects interest on increased debt levels during 2011, partially offset by prior year costs of $1.1 million that relate to the partial settlement of an interest rate swap. Excluding the effects of fair value adjustments to this swap in 2010, our aggregate effective interest rate was 6.7% for the year ended December 31, 2011 compared to 6.8% for 2010.

State Income Tax

We recorded state income taxes of $234,000 and $296,000 for the years ended December 31, 2011 and 2010, respectively, which are solely attributable to the Texas margin tax.

Table of Contentsril 19,

LIQUIDITY AND CAPITAL RESOURCES

Overview

In June 2012, we amended the Credit Agreement increasing the size of the credit facility from $375 million to $550 million. Our $550 million senior secured revolving credit facility expires in June 2017 and is available to fund capital expenditures, investments, acquisitions, distribution payments and working capital and for general partnership purposes. It also is available to fund letters of credit up to a $50 million sub-limit and to fund distributions to unitholders up to a $60 million sub-limit. In February 2012 we amended our credit agreement increasing the size of the credit facility from $275 million to $375 million.

During the year ended December 31, 2012, we received advances totaling $587.0 million and repaid $366.0 million, resulting in net advances of $221.0 million under the Credit Agreement and an outstanding balance of $421.0 million at December 31, 2012.

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. Additionally, we funded $260.0 million of the cash portion of our UNEV Pipeline interest acquisition from HFC on July 12, 2012 with advances under the Credit Agreement.

In February, May, August and November 2012, we paid regular quarterly cash distributions of $0.443, $0.448, $0.455 and $0.463, respectively, on all units in an aggregate amount of $122.8 million. Included in these distributions were $20.6 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 the next twelve consecutive quarterly periods and up to an additional four quarters in certain circumstances.

Cash and cash equivalents decreased by $1.1 million during the year ended December 31, 2012. The cash flows provided by operating activities of $161.4 million were less than the cash flows used for financing and investing activities of $119.7 million and $42.9 million, respectively. Working capital increased by $5.2 million to $11.8 million at December 31, 2012 from $6.6 million at December 31, 2011.

Cash Flows—Operating Activities

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

Cash flows from operating activities increased by $62.4 million from $99.0 million for the year ended December 31, 2011 to $161.4 million for the year ended December 31, 2012. This increase is due principally to $63.0 million in additional cash collections from our customers, partially offset by payments attributable to 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 $4.6 million during the year ended December 31, 2011 related to shortfalls that subsequently expired without recapture and were recognized as revenue during the year ended December 31, 2012. Another $7.8 million is included in our accounts receivable at December 31, 2012 related to shortfalls that occurred during the year ended December 31, 2012.

Year Ended December 31, 2011 Compared with Year Ended December 31, 2010
Cash flows from operating activities decreased by $5.7 million from $104.7 million for the year ended December 31, 2010 to $99.0 million for the year ended December 31, 2011. This decrease is due principally to payments attributable to increased interest and operating expenses, net of $11.1 million in additional cash collections from our customers.

We billed $10.4 million during the year ended December 31, 2010 related to shortfalls that subsequently expired without recapture and were recognized as revenue during the year ended December 31, 2011. We recognized an additional $2 million related to shortfalls billed in 2011 as a result of an amendment to our throughput agreement with Alon in June 2011 that limits the carryover term of credits attributable to such shortfall billings to the calendar year end in which the shortfalls occurred. Another $0.8 million was included in our accounts receivable at December 31, 2011 related to shortfalls that occurred in the fourth quarter of 2011.

Cash Flows—Investing Activities
Year Ended December 31, 2012 Compared with Year Ended December 31, 2011
Cash flows used for investing activities decreased by $163.4 million from $206.3 million for the year ended December 31, 2011 to $42.9 million for the year ended December 31, 2012. During the years ended December 31, 2012 and 2011, we invested $42.9 million and $206.3 million in additions to properties and equipment, respectively. The decrease is attributable to lower expenditures in 2012 as a result of the completion of the UNEV pipeline in 2011.

Year Ended December 31, 2011 Compared with Year Ended December 31, 2010
Cash flows used for investing activities increased by $64.3 million from $142.1 million for the year ended December 31, 2010 to $206.3 million for the year ended December 31, 2011. During the year ended December 31, 2011, we invested $206.3 million in additions to properties and equipment. During the year ended December 31, 2010, we paid $35.5 million in cash with respect to our asset acquisitions from HFC and invested $106.5 million in additions to properties and equipment. Capital expenditures for UNEV were $176.9 million and $84.4 million for the years ended December 31, 2011 and 2010, respectively.

Cash Flows—Financing Activities
Year Ended December 31, 2012 Compared with Year Ended December 31, 2011
Cash flows used for financing activities were $119.7 million for the year ended December 31, 2012 compared to cash provided of $105.6 million for the year ended December 31, 2011, a decrease of $225.3 million. 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 promissory notes. As partial consideration for the acquisition of HFC's 75% interest in UNEV on July 12, 2012, we paid HFC $260.9 million in cash (after a customary post-closing working capital adjustment). Additionally, we paid $122.8 million in regular quarterly cash distributions to our general and limited partners, 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. We also received contributions of $15.0 million from UNEV's joint venture partners. During the year ended December 31, 2011, we received $118.0 million and repaid $77.0 million in advances under the Credit Agreement, received proceeds of $75.8 million from the issuance of our common units, and repaid $77.1 million of our promissory notes. Additionally, we paid $91.5 million in regular quarterly cash distributions to our general and limited partners, we received $156.5 million from UNEV's joint venture partners, received $5.9 million from our general partner, incurred $3.2 million in financing costs upon the issuance of the 8.25% senior notes, and paid $1.6 million for the purchase of common units for recipients of our incentive grants.

Year Ended December 31, 2011 Compared with Year Ended December 31, 2010
Cash flows used for financing activities were $105.6 million for the year ended December 31, 2011, an increase of $69.7 million compared to $35.9 million for the year ended December 31, 2010. During the year ended December 31, 2011, we received $118.0 million and repaid $77.0 million in advances under the Credit Agreement, repaid $77.1

million on our promissory notes issued to HFC, received $75.8 million in proceeds from the issuance of our common units, received $5.9 million in capital contributions from our general partner, paid $91.5 million in regular quarterly cash distributions to our general and limited partners, we received $156.5 million from UNEV's joint venture partners, paid $1.6 million for the purchase of common units for recipients of our incentive grants and paid $3.2 million in financing costs to amend our previous credit agreement. During the year ended December 31, 2010, we received $66.0 million and repaid $113.0 million in advances under the Credit Agreement. Additionally, we received $147.5 million in net proceeds and incurred $0.5 million in financing costs upon the issuance of our 8.25% senior notes. Also in the year ended December 31, 2010, we paid $84.4 million in regular quarterly cash distributions to our general and limited partners, received $80.5 million from UNEV's joint venture partners, paid $57.6 million in excess of HFC’s transferred basis in the storage assets acquired in March 2010 and paid $2.7 million for the purchase of common units for recipients of our incentive grants.

Capital Requirements

Table of Contentsril 19,

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 HLS board of directors 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 2013 regular capital budget is comprised of $10.1 million for maintenance capital expenditures and $2.0 million for expansion capital expenditures exclusive of the projects discussed below. In addition to our capital budget, we may spend funds periodically to do capital upgrades of our assets where a customer reimburses us for such costs. These reimbursements would be required under contractual agreements and would generally benefit the customer over the remaining life of such agreements.

We recently have made certain modifications to our crude oil gathering and trunk line system that effectively have increased our ability to gather and transport an additional 10,000 barrels per day (“bpd”) of Delaware Basin crude oil in response to increased drilling activity in southeast New Mexico. We have a second project recently approved which consists of the reactivation and conversion to crude oil service of a 70-mile, 8-inch petroleum products pipeline owned by us. This project also includes the expansion and extension of several of our crude gathering systems and crude mainline pipes. Once in service, this system will be capable of transporting crude oil from southeast New Mexico to third-party common carrier pipelines in west Texas for further transport to major crude oil markets. This project is estimated to cost approximately $38.5 million and could be fully operational in late 2013.

We also are performing preliminary engineering, routing and cost estimates for two proposed new pipelines. The first proposed pipeline would be a new intrastate crude oil pipeline between Cushing, Oklahoma and HFC's Tulsa, Oklahoma refinery. The 50-mile line would provide safe and reliable transport of Cushing sourced domestic and Canadian crude oil to HFC's 125,000 BPD Tulsa facility. The pipeline would allow for a significant portion of crude oil transported to be heavy Canadian and sour crude oil. Crude oil processed at HFC's Tulsa facility currently is transported on pipelines owned by Sunoco Logistics and Magellan Pipeline Company. The second proposed pipeline would be a new 100-mile interstate petroleum products pipeline between HFC's Cheyenne, Wyoming refinery and Denver, Colorado. The 52,000 BPD refinery, with its ability to process up to 35,000 BPD of heavy Canadian crude and its close proximity to growing domestic crude production, is a significant supplier of petroleum products to the Denver market. The project also will evaluate the construction of a new petroleum products terminal in North Denver or, alternatively, the routing of the new pipeline to existing third-party product terminals in the Denver area. This infrastructure addition would ensure safe and reliable transport of petroleum products from HFC's location-advantaged refinery to its largest market. Petroleum products produced at HFC's Cheyenne, Wyoming refinery are currently transported to Denver on the Rocky Mountain Pipeline’s products line owned by Plains All-American. We anticipate that we will be in a position to decide whether to proceed with these projects in the second quarter of 2013 when preliminary engineering and detailed project cost estimates are completed and if necessary shipper commitments can be secured.

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 existing 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.

On July 12, 2012, we acquired HFC's 75% interest in UNEV. We paid consideration consisting of $260.0 million in cash and 2,059,800 of our common units (adjusted to reflect the unit split). We paid an additional $0.9 million to HFC for a post-closing working capital adjustment as provided for by the acquisition agreement. As a result of the common units issued to HFC, HFC's ownership interest in us increased from 42% to 44% (including the 2% general partner interest). 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 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 the next twelve consecutive quarterly periods and up to an additional four quarters in certain circumstances. The Class B unit has an initial value of $12.2 million which will increase with each foregone incentive distribution as described above 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. Noncontrolling interests reported in the Consolidated Statements of Income include the minority partner's 25% interest in UNEV and income attributable to the Class B unit representing foregone incentive distribution rights and the 7% accretion factor, which collectively amounted to $1.2 million for the period July 12, 2012 to December 31, 2012.

Credit Agreement
In June 2012, we amended our credit agreement increasing the size of the credit facility from $375 million to $550 million. Our $550 million senior secured revolving credit facility expires in June 2017 (the “Credit Agreement”) and is available to fund capital expenditures, investments, acquisitions, distribution payments and working capital and for general partnership purposes. It is available also to fund letters of credit up to a $50 million sub-limit and to fund distributions to unitholders up to a $60 million sub-limit. In February 2012 we amended our credit agreement increasing the size of the credit facility from $275 million to $375 million.

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 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 0.75% to 1.75%) or (b) at a rate equal to LIBOR plus an applicable margin (ranging from 1.75% to 2.75%). 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 0.50% 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 that we are currently in compliance with, 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 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 1, 2020 (the “6.5% Senior Notes”). Net Proceeds of $294.8 million were used to redeem $157.8 million aggregate principal amount of 6.25% senior notes maturing March 1, 2015 (the “6.25 Senior Notes”) tendered pursuant

to a cash tender offer and consent solicitation, to repay $72.9 million in promissory notes due to HFC as discussed below, to pay related fees, expenses and accrued interest in connection with these transactions and to repay borrowings under the Credit Agreement. In April 2012, we redeemed $27.2 million aggregate principal amount of 6.25% Senior Notes that remained outstanding following the cash tender offer and consent solicitation.

We also have $150 million in aggregate principal amount outstanding of 8.25% senior notes maturing March 15, 2018 (the “8.25 Senior Notes”).

Our 6.5% Senior Notes and 8.25% Senior Notes (collectively, the “Senior Notes”) are unsecured and impose certain restrictive covenants which we are currently in compliance with, 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 Senior Notes are rated investment grade by both Moody’s and Standard & Poor’s and no default or event of default

Table of Contentsril 19,

exists, we will not be subject to many of the foregoing covenants. Additionally, we have certain redemption rights under the Senior Notes.

Indebtedness under the Senior Notes is recourse to HEP Logistics, and guaranteed by our 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.

Promissory Notes

In November 2011, we issued senior unsecured promissory notes to HFC (the “Promissory Notes”) having an aggregate principal amount of $150.0 million to finance a portion of our November 9, 2011 acquisition of assets located at HFC's El Dorado and Cheyenne refineries. In December 2011, we repaid $77.1 million of outstanding principal using proceeds received in our December 2011 common unit offering and existing cash. We repaid the remaining $72.9 million balance in March 2012.

Long-term Debt

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

	December 31, 2012	December 31, 2011
	(In thousands)	
Credit Agreement	$421,000	$200,000
6.5% Senior Notes		
Principal	300,000	—
Unamortized discount	(4,725)	—
	295,275	—
6.25% Senior Notes		
Principal	—	185,000
Unamortized net discount	—	(105)
	—	184,895
8.25% Senior Notes		
Principal	150,000	150,000
Unamortized discount	(1,601)	(1,907)
	148,399	148,093
Promissory Notes	—	72,900
Total long-term debt	$864,674	$605,888

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, 2012.

		Payments Due by Period			
	Total	Less than	1-3 Years	3-5 Years	Over 5

		1 Year			Years
	(In thousands)				
Long-term debt – principal	$ 871,000	$ —	$ —	$ 421,000	$ 450,000
Long-term debt - interest	260,951	42,239	84,478	79,296	54,938
Pipeline operating lease	36,693	6,672	13,343	13,343	3,335
Right-of-way leases	1,340	237	356	325	422
Other	16,210	1,519	2,967	2,725	8,999
Total	$ 1,186,194	$ 50,667	$ 101,144	$ 516,689	$ 517,694

Long-term debt consists of outstanding principal under the Credit Agreement, Senior Notes and Promissory Notes. Interest on the credit agreement is calculated using the rate in effect at December 31, 2012.
The pipeline operating lease amounts above reflect the exercise of the first of three 10-year extensions, expiring in 2017, on our lease agreement for the refined products pipeline between White Lakes Junction and Kuntz Station in New Mexico. However, these amounts exclude the second and third 10-year lease extensions, which based on the current outlook, are likely to be exercised.
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, 2012. 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 2027, for the provision of certain maintenance 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, 2012, 2011 and 2010. Historically, the PPI has increased an average of 3.1% annually over the past 5 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 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 transportation and storage of refined products and crude oil 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. While these laws and regulations affect our maintenance capital expenditures and net income, we believe that they do not affect our competitive position given 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.
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.
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.

There are environmental remediation projects that are 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 as the obligation for future remediation activities was retained by HFC. At December 31, 2012, we have an accrual of $3.0 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.

Table of Contentsril 19,

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 definite-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, 2012.

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.

RISK MANAGEMENT

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

As of December 31, 2012, 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 2.25% as of December 31, 2012, which equaled an effective interest rate of 3.24%. This swap contract matures in

Table of Contentsril 19,

February 2016. In August 2012, we entered into two similar 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 2.25% as of December 31, 2012, which equaled an effective interest rate of 2.99%. Both of these swap contracts mature in July 2017.

We review publicly available information on our counterparties in order to review and 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, 2012, we had an outstanding principal balance on our 6.5% Senior Notes and 8.25% Senior Notes of $300 million and $150 million, respectively. A change in interest rates generally would affect the fair value of the Senior Notes, but not our earnings or cash flows. At December 31, 2012, the fair values of our 6.5% Senior Notes and 8.25% Senior Notes were $321.0 million and $163.1 million, respectively. We estimate a hypothetical 10% change in the yield-to-maturity applicable to the 6.5% Senior Notes and 8.25% Senior Notes at December 31, 2012 would result in a change of approximately $9.9 million and $4.4 million, respectively, 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, 2012, borrowings outstanding under the Credit Agreement were $421.0 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 $116.0 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” above 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, also 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.

Table of Contentsril 19,

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, 2012 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. Based on this assessment, management concluded that, as of December 31, 2012, 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, 2012. That report appears on page 54.

Table of Contentsril 19,

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 internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the 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, 2012, 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, 2012 and 2011, 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, 2012, and our report dated February 27, 2013, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP
Dallas, Texas
February 27, 2013

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, 2012 and 2011, 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, 2012. 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, 2012 and 2011, and the consolidated results of its operations and its cash flows, for each of the three years in the period ended December 31, 2012, 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, 2012, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2013 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP
Dallas, Texas
February 27, 2013

Table of Contentsril 19,

HOLLY ENERGY PARTNERS, L.P.
CONSOLIDATED BALANCE SHEETS

	December 31, 2012	December 31, 2011 [1]
	(In thousands, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$5,237	$6,369
Accounts receivable:		
Trade	7,126	6,130
Affiliates	31,594	31,922
	38,720	38,052
Prepaid and other current assets	3,619	3,729
Total current assets	47,576	48,150
Properties and equipment, net	960,535	960,499
Transportation agreements, net	94,596	101,543
Goodwill	256,498	256,498
Investment in SLC Pipeline	25,041	25,302
Other assets	9,864	7,204
Total assets	$1,394,110	$1,399,196
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$7,045	$18,375
Affiliates	4,985	6,474
	12,030	24,849
Accrued interest	10,226	8,280
Deferred revenue	8,901	4,447
Accrued property taxes	2,688	2,196
Other current liabilities	1,905	1,777
Total current liabilities	35,750	41,549
Long-term debt	864,674	605,888
Other long-term liabilities	15,433	8,653
Deferred revenue	11,494	5,428
Class B unit	13,903	—
Equity:		
Partners' equity:		
Common unitholders (56,782,048 and 54,722,248 units issued and outstanding at December 31, 2012 and 2011, respectively)	502,809	481,439
General partner interest (2% interest)	(145,877)	163,701
Accumulated other comprehensive loss	(4,279)	(6,464)
Total partners' equity	352,653	638,676

Noncontrolling interest	100,203	99,002
Total equity	452,856	737,678
Total liabilities and equity	$1,394,110	$1,399,196

(1) Restated as described in Note 2.

See accompanying notes.

Table of Contentsril 19,

HOLLY ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2012	2011 (1)	2010 (1)
	(In thousands, except per unit data)		
Revenues:			
Affiliates	$245,582	$168,261	$146,367
Third parties	46,978	46,007	35,770
	292,560	214,268	182,137
Operating costs and expenses:			
Operations (exclusive of depreciation and amortization)	89,242	64,521	54,946
Depreciation and amortization	57,461	36,958	31,363
General and administrative	7,594	6,576	7,719
	154,297	108,055	94,028
Operating income	138,263	106,213	88,109
Other income (expense):			
Equity in earnings of SLC Pipeline	3,364	2,552	2,393
Interest expense	(47,182)	(35,959)	(33,994)
Loss on early extinguishment of debt	(2,979)	—	—
Other (income) expense	10	17	17
	(46,787)	(33,390)	(31,584)
Income before income taxes	91,476	72,823	56,525
State income tax expense	(371)	(234)	(296)
Net income	91,105	72,589	56,229
Allocation of net loss attributable to Predecessors	4,200	6,351	70
Allocation of net loss (income) attributable to noncontrolling interests	(1,153)	859	24
Net income attributable to Holly Energy Partners	94,152	79,799	56,323
General partner interest in net income, including incentive distributions	(22,450)	(16,806)	(12,084)
Limited partners' interest in net income	$71,702	$62,993	$44,239
Limited partners' per unit interest in earnings—basic and diluted	$1.29	$1.38	$1.00
Weighted average limited partners' units outstanding	55,696	45,672	44,157

(1) Restated as described in Note 2.

See accompanying notes.

HOLLY ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2012	2011 [1]	2010 [1]
	(In thousands)		
Net income	$91,105	$72,589	$56,229
Allocation of net loss attributable to Predecessors	4,200	6,351	70
Net income before noncontrolling interests	95,305	78,940	56,299
Other comprehensive income (loss):			
Change in fair value of cash flow hedge	(2,910)	3,521	(1,961)
Amortization of unrealized loss attributable to discontinued cash flow hedge	5,095	41	—
Reclassification adjustment to net income on partial settlement of cash flow hedge	—	—	1,076
Other comprehensive income (loss)	2,185	3,562	(885)
Comprehensive income before noncontrolling interest	97,490	82,502	55,414
Allocation of comprehensive (income) loss to noncontrolling interests	(1,153)	859	24
Comprehensive income	$96,337	$83,361	$55,438

[1] Restated as described in Note 2.

See accompanying notes.

Table of Contentsril 19,

HOLLY ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2012	2011 (1)	2010 (1)
	(In thousands)		
Cash flows from operating activities			
Net income	$91,105	$72,589	$56,229
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	57,461	36,958	31,363
Amortization of deferred charges	7,556	1,253	1,008
Equity in earnings of SLC Pipeline, net of distributions	262	135	482
Change in fair value - interest rate swaps	—	—	1,464
Amortization of restricted and performance units	2,858	2,046	2,214
(Increase) decrease in operating assets:			
Accounts receivable—trade	(3,997)	489	1,149
Accounts receivable—affiliates	(135)	(13,032)	(4,888)
Prepaid and other current assets	110	(2,491)	(36)
Current assets of discontinued operations	—	—	2,195
Increase (decrease) in operating liabilities:			
Accounts payable—trade	(9,003)	3,894	2,684
Accounts payable—affiliates	(1,811)	2,137	1,487
Accrued interest	1,945	763	4,654
Deferred revenue	11,333	(2,127)	3,664
Accrued property taxes	492	206	918
Other current liabilities	113	515	5
Other, net	3,122	(4,293)	144
Net cash provided by operating activities	161,411	99,042	104,736
Cash flows from investing activities			
Additions to properties and equipment	(42,861)	(206,309)	(106,525)
Acquisition of assets from HFC	—	—	(35,526)
Net cash used for investing activities	(42,861)	(206,309)	(142,051)
Cash flows from financing activities			
Borrowings under credit agreement	587,000	118,000	66,000
Repayments of credit agreement borrowings	(366,000)	(77,000)	(113,000)
Proceeds from issuance of senior notes	294,750	—	147,540
Proceeds from issuance of common units	—	75,815	—
Cash distribution to HFC for UNEV Acquisition	(260,922)	—	—
Repayment of notes	(260,235)	(77,100)	—
Contributions from UNEV joint venture partners	15,000	156,500	80,500
Contributions from general partner	1,748	5,887	—
Distributions to HEP unitholders	(122,777)	(91,506)	(84,426)
Purchase price in excess of transferred basis in assets acquired from HFC	—	—	(57,560)
Purchase of units for incentive grants	(4,919)	(1,641)	(2,704)
Deferred financing costs	(3,238)	(3,150)	(494)

Other	(89)	(221)	—
Net cash provided (used) by financing activities	(119,682)	105,584	35,856
Cash and cash equivalents			
Increase (decrease) for the period	(1,132)	(1,683)	(1,459)
Beginning of year	6,369	8,052	9,511
End of year	$5,237	$6,369	$8,052

(1) Restated as described in Note 2.

See accompanying notes.

Table of Contentsril 19,

HOLLY ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY

	Holly Energy Partners, L.P. Partners' Equity (Deficit):					
	Common Units (1)	Class B Subordinated Units (1)	General Partner Interest (1)	Accumulated Other Comprehensive Loss (1)	Noncontrolling Interest (1)	Total (1)
	(In thousands)					
Balance December 31, 2009	$275,553	$ 21,426	$25,678	$ (9,141)	$ 39,886	$353,402
Conversion of Class B subordinated units	20,588	(20,588)	—	—	—	—
Capital contribution			75,091		23,500	98,591
Distributions to unitholders	(70,886)	(1,519)	(12,021)	—	—	(84,426)
Purchase price in excess of transferred basis in assets acquired from HollyFrontier	—	—	(57,560)	—	—	(57,560)
Purchase of units for incentive grants	(2,704)	—	—	—	—	(2,704)
Amortization of restricted and performance units	2,214	—	—	—	—	2,214
Comprehensive income:						
Net income	44,388	681	11,254	—	(24)	56,299
Net loss - Predecessor	—	—	(70)	—	—	(70)
Other comprehensive loss	—	—	—	(885)	—	(885)
Balance December 31, 2010	269,153	—	42,372	(10,026)	63,362	364,861
Issuance of common units	75,815	—	—	—	—	75,815
Cost of issuing common units	(308)	—	—	—	—	(308)
Capital contribution	—	—	127,947	—	36,500	164,447
Distributions to unitholders	(75,951)	—	(15,555)	—	—	(91,506)
Tankage and terminal assets acquired from HFC:						
Transferred basis in properties and goodwill	295,110	—	—	—	—	295,110
Operating costs prior to acquisition	2,348	—	—	—	—	2,348
Promissory notes issued	(150,000)	—	—	—	—	(150,000)
Purchase of units for incentive grants	(2,168)	—	—	—	—	(2,168)
Amortization of restricted and performance units	2,046	—	—	—	—	2,046
Other	640	—	242	—	—	882
Comprehensive income:						
Net income	64,754	—	15,046	—	(860)	78,940
Net loss - Predecessor	—	—	(6,351)	—	—	(6,351)
Other comprehensive income	—	—	—	3,562	—	3,562
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 restricted 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
Comprehensive income:						
Net income	70,877	—	26,227	—	(1,799)	95,305
Net loss - Predecessor	—	—	(4,200)	—	—	(4,200)
Other comprehensive income	—	—	—	2,185	—	2,185
Balance December 31, 2012	$502,809	$ —	$(145,877)	$ (4,279)	$ 100,203	$452,856

(1) Restated as described in Note 2.

See accompanying notes.

- 61 -

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2012

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 44% 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 recently constructed 400-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 we own 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 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.

On November 29, 2012, we announced a two-for-one unit split, payable in the form of a common unit distribution for each issued and outstanding common unit. The unit distribution was paid January 16, 2013 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 periods presented.

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. If these assets had been acquired from third parties, our acquisition cost in excess of HFC's basis in the transferred assets of $305.6 million would have been recorded as increases to our properties and equipment and intangible assets instead of reductions to our partners' equity.

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.

Inventories
Inventories consisting of materials and supplies used for operations are stated at the lower of cost, using the average cost method, or market and are shown under “Prepaid and other current assets” in our consolidated balance sheets.

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. 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 6 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 definite-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, 2012.

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, 2012, our underlying equity in the SLC Pipeline was $60.0 million compared to our recorded investment balance of $25.0 million, a difference of $35.0 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 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. At December 31, 2012 and 2011, we have retirement obligations of $5.6 million and $3.6 million, respectively, that are recorded under “Other long-term liabilities” in our consolidated

balance sheets. During 2012 we increased our asset retirement obligations by an additional $2.9 million as a result of a change in our previous estimates.

Revenue Recognition

Revenues are recognized as products are shipped through our pipelines and terminals or other services have been 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 pipeline transportation revenues under an operating lease to a third party of an interest in the capacity of one of our pipelines.

As of December 31, 2012, 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 of $256.7 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 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, 2012 and 2011, we had net accruals for environmental remediation obligations of $3.0 million and $2.7 million, respectively, measured on an undiscounted basis.
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, by the weighted-average number of outstanding common and subordinated units.

Note 2: Revisions to Prior Period Financial Statements

We have revised our previously reported consolidated financial statements. The revisions were due to accounting rules that require retrospective restatement of previously reported results in cases of business combinations between entities under common control. Additional revisions for the years ended December 31, 2011 and 2010 were done in order to correct items in certain previously reported amounts.

Our retrospective restatements for two acquisitions from HFC are described below. See Note 3 below for additional information on both acquisitions.

- On July 12, 2012, we acquired a 75% interest in UNEV. We have retrospectively adjusted our historical financial results for all periods to include UNEV for the periods we were under common control of HFC. Results of operations of UNEV prior to the acquisition on July 12, 2012 are herein referred to as the results of operations attributable to the Predecessor.

- In 2011, our operating results included $3.8 million of operating costs and depreciation incurred by HFC prior to our November 9, 2011 acquisition of certain assets located at HFC's El Dorado and Cheyenne refineries. This loss was allocated in the originally reported historical financial statements included in Form 10-K for the year ended December 31, 2011 principally to the limited partners. The pre-acquisition loss should have been reported as a loss attributable to the Predecessor. We have revised the 2011 presentation which resulted in an increase in limited partners' interest in net income of $3.8 million and limited partners' per unit interest in earnings - basic and diluted of $0.08 from the amounts originally reported.

During 2012, we identified the following additional items requiring revisions to our previously reported financial statements for the years ended December 31, 2011 and 2010, which have been corrected. We determined that the effects of these corrections in each of the periods in which the related items originated, as described below, were not material. We have concluded that the amounts, if corrected in 2012, would have been material to the consolidated financial statements as of and for the year ended December 31, 2012.

- Depreciation expense was understated related to property and equipment in both 2010 and 2011 due to inappropriate depreciable lives for certain property and equipment and untimely recording of acceleration of depreciation for tankage placed permanently out of service in prior periods.

- An environmental remediation liability and certain asset retirement obligations were identified that should have been recorded in 2010 and 2011.

- Reimbursement payments from HFC under contractual arrangements previously recognized as an offset against the related costs have been recorded as revenue, or deferred revenue in cases of capital cost reimbursements which are then amortized over the contractual term of the related throughput agreement. Additionally, we have revised our cash flow presentation for capital cost reimbursements to reflect receipts in cash flows provided by operating activities as opposed to netting the receipts in cash flows used for investing activities.

The tables below outline the impact of such corrections on individual financial statement line items.

	December 31, 2011 Increase (Decrease) (In thousands)
Consolidated Balance Sheets:	
Properties and equipment, net	$5,635
Deferred revenue - current portion	$415
Other long-term liabilities	$4,653
Deferred revenue - long-term	$5,428
Total equity	$(4,861)

	Years Ended December 31,	
	2011	2010
	Increase (Decrease) (In thousands)	
Consolidated Statements of Income:		
Revenues	$976	$55
Operating expenses	$898	$1,808
Depreciation and amortization	$2,050	$794
Net income attributable to Holly Energy Partners and comprehensive income	$(1,972)	$(2,547)
Limited partners' per unit interest in earnings - basic and diluted	$(0.04)	$(0.06)
Consolidated Statements of Cash Flows:		
Net cash provided by operating activities	$4,278	$1,629
Net cash used for investing activities	$(4,278)	$(1,629)

Note 3: Acquisitions

2012 UNEV Acquisition

On July 12, 2012, we acquired HFC's 75% interest in UNEV. We paid consideration consisting of $260.0 million in cash and 2,059,800 of our common units (adjusted to reflect the unit split). We paid an additional $0.9 million to HFC for a post-closing working capital adjustment as provided for by the acquisition agreement. As a result of the common units issued to HFC, HFC's ownership interest in us increased from 42% to 44% (including the 2% general partner interest). 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 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 the next twelve consecutive quarterly periods and up to an additional four quarters in certain circumstances. The Class B unit has an initial value of $12.2 million which will increase with each foregone incentive distribution as described above 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. Noncontrolling interests reported in the Consolidated Statements of Income include the minority partner's 25% interest in UNEV and income attributable to the Class B unit representing foregone incentive distribution rights and the 7% accretion factor, which collectively amounted to $1.2 million for the period July 12, 2012 to 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. For the year ended December 31, 2012 and 2011, our consolidated statement of income includes revenues from UNEV of $18.7 million and $0.3 million, respectively, net losses of $7.2 million and $3.4 million, respectively. Predecessor revenues for the years ended December 31, 2012 and 2011 are $8.1 million and $0.3 million, respectively, and Predecessor net losses are $4.2 million and $2.6 million, respectively. For the year ended December 31, 2010, there were no Predecessor revenues as UNEV was not yet operational and Predecessor net losses were $0.1 million. At December 31, 2012, UNEV had transportation agreements with shippers that provide minimum annualized revenues of $25.0 million, of which $16.9 million relates to a transportation agreement with HFC.

The following table provides HFC's carrying basis related to UNEV on July 12, 2012, immediately prior to the acquisition, and at December 31, 2011.

	July 12, 2012	December 31, 2011 [1]
	(In thousands)	
Current assets	$7,083	$8,265
Properties and equipment, net	418,764	418,439
Total assets	$425,847	$426,704
Current liabilities	$7,040	$13,542
General partner interest related to Predecessor	318,310	314,160
Noncontrolling interest	100,497	99,002
Total liabilities and equity	$425,847	$426,704

[1] Our previously reported balance sheet as of December 31, 2011 has been recast to include such balances.

2011 Legacy Frontier Pipeline and Tankage Asset Transaction
On November 9, 2011, we acquired from HFC certain tankage, loading rack and crude receiving assets located at HFC’s El Dorado and Cheyenne refineries. We paid non-cash consideration consisting of promissory notes with an aggregate principal amount of $150.0 million and 7,615,230 of our common units. As an entity under common control with HFC, we recorded this transfer at HFC's carrying basis. We recorded properties and equipment of $88.1 million, goodwill of $207.4 million and a non-cash capital contribution of $295.5 million, representing HFC's cost basis in the acquired assets. On November 9, 2011, we recorded a $150.0 million liability representing the promissory notes issued to HFC at the time of the closing of this transaction. In 2012, we recorded additional properties and equipment of $7.6 million, and a related non-cash capital contribution of $7.6 million for newly constructed tankage conveyed in 2012 as part of the November 9, 2011 transaction.

Summary Pro Forma Information
Assuming both acquisitions had occurred on January 1, 2010 and our throughput agreements with HFC were in effect at that time, pro forma revenues, net income and earnings per unit are presented below:

	Years Ended December 31,	
	2011	2010
	(In thousands, except per share amounts)	
	(unaudited)	
Revenues	$214,268	$182,137
Net income	71,145	47,669
Earnings per unit	$1.19	$0.81

2010 Tulsa East / Lovington Storage Asset Transaction
On March 31, 2010, we acquired from HFC certain storage assets for $88.6 million consisting of hydrocarbon storage tanks having approximately 2 million barrels of storage capacity, a rail loading rack and a truck unloading rack located at HFC's Tulsa refinery east facility. Also, as part of this same transaction, we acquired HFC's asphalt loading rack facility located at its Navajo refinery facility in Lovington, New Mexico for $4.4 million. In accounting for the 2010 acquisition from HFC, we recorded total property and equipment at HFC's historical basis of $35.5 million and the purchase price in excess of HFC's basis in the assets of $57.6 million as a decrease to our partners' equity.

- 67 -

Note 4: 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:

		December 31, 2012		December 31, 2011	
Financial Instrument	Fair Value Input Level	Carrying Value	Fair Value	Carrying Value	Fair Value
		(In thousands)			
Liabilities:					
Senior notes:					
6.25% senior notes	Level 2	$—	$—	$184,895	$186,850
6.5% senior notes	Level 2	295,275	321,000	—	—
8.25% senior notes	Level 2	148,398	163,125	148,093	157,500
		443,673	484,125	332,988	344,350
Interest rate swaps	Level 2	3,430	3,430	520	520
		$447,103	$487,555	$333,508	$344,870

Level 2 Financial Instruments

Our senior notes and interest rate swaps are measured and recorded 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 8 for additional information on these instruments.

Note 5: Properties and Equipment

The carrying amounts of our properties and equipment after restatement as per Note 2 are as follows:

	December 31, 2012	December 31, 2011
	(In thousands)	
Pipelines, terminals and tankage	1,049,531	886,167
Land and right of way	63,248	43,904
Construction in progress	27,150	172,485
Other	24,462	17,554
	1,164,391	1,120,110
Less accumulated depreciation	203,856	159,611
	$960,535	$960,499

We capitalized $0.3 million and $0.9 million in interest related to construction projects during the years ended December 31, 2012 and 2011, respectively.

Depreciation expense was $50.1 million, $30.0 million, and $24.5 million for the years ended December 31, 2012, 2011 and 2010, respectively. Included in depreciation expense were asset abandonment charges of $4.8 million, $1.2 million and $0.4 million for the years ended December 31, 2012, 2011 and 2010, respectively, for assets permanently removed from service.

Note 6: 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, 2012	December 31, 2011
	(In thousands)	
Alon transportation agreement	$59,933	$59,933
HFC transportation agreement	74,231	74,231
	134,164	134,164
Less accumulated amortization	39,568	32,621
	$94,596	$101,543

Amortization expense was $6.9 million, $6.9 million, and $6.9 million for the years ended December 31, 2012, 2011 and 2010, respectively.

We have additional transportation agreements with HFC that relate to assets contributed to us or acquired from HFC consisting of pipeline, terminal and tankage assets. 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 7: Employees, Retirement and Incentive Plans

Employees who provide direct services to us are employed by Holly Logistic Services, L.L.C., an HFC subsidiary. 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 $6.9 million, $3.6 million and $2.9 million for the years ended December 31, 2012, 2011 and 2010, respectively. These costs include retirement costs of $4.3 million, $2.2 million and $1.5 million for the years ended December 31, 2012, 2011 and 2010, respectively. 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.

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 units, performance units, unit options and unit appreciation rights.

As of December 31, 2012, we have two types of incentive-based awards which are described below. The compensation cost charged against income was $2.7 million, $2.1 million and $2.2 million for the years ended December 31, 2012, 2011 and 2010, 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. Effective February 2012, the units authorized to be granted under our Long-Term Incentive Plan were increased from 700,000 to 2,500,000 units, of which 1,833,024 have not yet been granted, assuming no forfeitures of the unvested units and full achievement of goals for the performance units already granted.

Restricted Units
Under our Long-Term Incentive Plan, we grant restricted units to selected employees and non-employee directors 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. The fair value of each restricted 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 activity and changes during the year ended December 31, 2012 is presented below:

Restricted Units	Units		Weighted-Average Grant-Date Fair Value	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value ($000)
Outstanding at January 1, 2012 (nonvested)	59,072		$25.23		
Granted	90,528		31.01		
Vesting and transfer of full ownership to recipients	(89,034	)	27.10		
Forfeited	(2,094	)	28.66		
Outstanding at December 31, 2012 (nonvested)	58,472		$31.21	1.1 years	$1,923

The fair values of restricted units that were vested and transferred to recipients during the years ended December 31, 2012, 2011 and 2010 were $2.4 million, $1.4 million and $1.6 million respectively. As of December 31, 2012, there was $1.0 million of total unrecognized compensation expense related to nonvested restricted unit grants which is expected to be recognized over a weighted-average period of 1.1 years. For the years ended December 31, 2011 and 2010, the grant date closing unit price applied to the number of units ultimately awarded was $29.05 and 21.57 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 3 years. As of December 31, 2012, estimated unit payouts for outstanding nonvested performance unit awards were 110%.

We granted 11,436 performance units to certain officers in March 2012. These units will vest over a 3-year performance period ending December 31, 2014 and 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 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. For the year ended December 31, 2012, the fair value of these performance units is based on the grant date closing unit price of $30.61 and will apply to the number of units ultimately awarded. For the years ended December 31, 2011 and 2010, the grant date closing unit price applied to the number of units ultimately awarded was $29.83 and $21.30 respectively.

A summary of performance unit activity and changes during the twelve months ended December 31, 2012 is presented below:

Performance Units	Units
Outstanding at January 1, 2012 (nonvested)	85,982
Granted	11,436
Vesting and transfer of common units to recipients	(42,920)
Outstanding at December 31, 2012 (nonvested)	54,498

The grant-date fair value of performance units vested and transferred to recipients during the years ended December 31, 2012, 2011 and 2010 was $0.5 million, $0.9 million and $0.6 million, respectively. Based on the weighted average fair value at December 31, 2012 of $26.06, there was $0.5 million of total unrecognized compensation expense related to nonvested performance units, which is expected to be recognized over a weighted-average period of 0.6 years.

During the year ended December 31, 2012, we paid $4.9 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 8: Debt

Credit Agreement

In June 2012, we amended our credit agreement increasing the size of the credit facility from $375 million to $550 million. Our $550 million senior secured revolving credit facility expires in June 2017 (the "Credit Agreement") and is available to fund capital expenditures, investments, acquisitions, distribution payments and working capital and for general partnership purposes. It is available also to fund letters of credit up to a $50 million sub-limit and to fund distributions to unitholders up to a $60 million sub-limit. In February 2012, we amended our credit agreement increasing the size of the credit facility from $275 million to $375 million. During the year ended December 31, 2012, we received advances totaling $587 million and repaid $366 million, resulting in net borrowings of $221 million under the Credit Agreement and an outstanding balance of $421 million at December 31, 2012.

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 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 0.75% to 1.75%) or (b) at a rate equal to LIBOR plus an applicable margin (ranging from 1.75% to 2.75%). 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 0.50% 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 which we are currently in compliance with, 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 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 1, 2020 (the “6.5% Senior Notes”). Net proceeds of $294.8 million were used to redeem $157.8 million aggregate principal amount of our 6.25% senior notes maturing March 1, 2015 (the “6.25% Senior Notes”) tendered pursuant to a cash tender offer and consent solicitation, to repay $72.9 million in promissory notes due to HFC as discussed below, to pay related fees, expenses and accrued interest in connection with these transactions and to repay borrowings under the Credit Agreement.

In April 2012, we redeemed $27.2 million aggregate principal amount of 6.25% Senior Notes that remained outstanding following the cash tender offer and consent solicitation.

We also have $150 million in aggregate principal amount outstanding of 8.25% senior notes maturing March 15, 2018 (the “8.25% Senior Notes”).

The 6.5% Senior Notes and 8.25% Senior Notes (collectively, the “Senior Notes”) are unsecured and impose certain restrictive covenants, which we are currently in compliance with, 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 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 under the Senior Notes.

Indebtedness under the Senior Notes is recourse to HEP Logistics, our general partner, and guaranteed by our 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.

Promissory Notes
In November 2011, we issued senior unsecured promissory notes to HFC (the “Promissory Notes”) having an aggregate principal amount of $150 million to finance a portion of our November 9, 2011 acquisition of assets located at HFC's El Dorado and Cheyenne refineries (see Note 3). In December 2011, we repaid $77.1 million of outstanding principal using proceeds received in our December 2011 common unit offering and existing cash. We repaid the remaining $72.9 million balance in March 2012.

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

	December 31, 2012	December 31, 2011
	(In thousands)	
Credit Agreement	$421,000	$200,000
6.5% Senior Notes		
Principal	300,000	—
Unamortized discount	(4,725)	—
	295,275	—
6.25% Senior Notes		
Principal	—	185,000
Unamortized net discount	—	(105)
	—	184,895
8.25% Senior Notes		
Principal	150,000	150,000
Unamortized discount	(1,601)	(1,907)
	148,399	148,093
Promissory Notes	—	72,900

Total long-term debt	$864,674	$605,888

Maturities of our long-term debt are as follows:

Years Ending December 31,	(In thousands)
2013	$—
2014	—
2015	—
2016	—
2017	421,000
Thereafter	450,000
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, 2012, 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 entered into in December 2011, 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 2.25% as of December 31, 2012, which equaled an effective interest rate of 3.24%. This swap contract matures in February 2016. In August 2012, we entered into two similar 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 2.25% as of December 31, 2012, which equaled an effective interest rate of 2.99%. 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 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, 2012, we had no ineffectiveness on our cash flow hedges.

Prior to entering into our swap contract in December 2011 (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.

At December 31, 2012, we have an accumulated other comprehensive loss of $4.3 million that relates to our current and previous cash flow hedging instruments. Of this amount, $0.8 million represents an unrecognized loss attributable to a cash flow hedge terminated in December 2011 and relates to the application of hedge accounting prior to termination. This amount is being amortized as a charge to interest expense through February 2013, the remaining term of the terminated swap contract. Of the remaining $3.4 million, approximately $1.0 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, 2012				
Interest rate swap designated as cash flow hedging instrument:				
Variable-to-fixed interest rate swap contract ($305.0 million of LIBOR based debt interest)	Other long-term liabilities	$3,430	Accumulated other comprehensive loss	$3,430
December 31, 2011				
Interest rate swap designated as cash flow hedging instrument:				
Variable-to-fixed interest rate swap contract ($155.0 million of LIBOR based debt interest)	Other long-term liabilities	$520	Accumulated other comprehensive loss	$520

We previously had interest rate swap contracts that served as economic hedges on interest attributable to outstanding debt. For the year ended December 31, 2010, we recognized $1.5 million in non-cash charges to interest expense as a result of fair value adjustments to these swap contracts.

We have a deferred hedge premium that relates to the application of hedge accounting to a variable-rate swap associated with our 6.25% senior notes prior to its hedge dedesignation in 2008. This deferred hedge premium having a balance of $1.1 million at December 31, 2011 was amortized in 2012 and the unamortized balance was taken as a reduction to interest expense during the cash tender offer and consent solicitation of our 6.25% Senior Notes.

Interest Expense and Other Debt Information

Interest expense consists of the following components:

	Years Ended December 31,		
	2012	2011	2010
	(In thousands)		
Interest on outstanding debt:			
Credit Agreement, net of interest on interest rate swaps	$8,736	$10,477	$9,109
6.5% Senior Notes	15,716	—	—
6.25% Senior Notes	2,422	11,565	11,404
8.25% Senior Notes	12,380	12,380	10,298
Promissory Notes	543	745	—
Partial settlement of interest rate swap - cash flow hedge	—	—	1,076
Net fair value adjustments to interest rate swaps (1)	—	—	1,464
Amortization of unrealized loss attributable to discounted cash flow hedge	5,095	41	—
Amortization of discount and deferred debt issuance costs	1,946	1,212	713
Commitment fees	621	430	392
Total interest incurred	47,459	36,850	34,456
Less capitalized interest	277	891	462
Net interest expense	$47,182	$35,959	$33,994
Cash paid for interest (2)	$38,476	$34,825	$31,305

(1) Includes fair value adjustments to previous interest rate swap contracts settled during the first quarter of 2010.

(2) Presented net of cash received under previous interest rate swap contract of $1.9 million for the year ended December 31, 2010.

We recognized a charge of $3.0 million upon the early extinguishment of debt 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.

Note 9: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, 2012, 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)
2013	$6,908
2014	6,852
2015	6,848
2016	6,847
2017	6,821
Thereafter	3,758
Total	$38,034

Rental expense charged to operations was $8.1 million, $7.5 million and $7.1 million for the years ended December 31, 2012, 2011 and 2010, respectively.

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 10: Significant Customers

All revenues are domestic revenues, of which 95% 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:

	2012		2011		2010	
HFC	84	%	79	%	80	%
Alon	11	%	18	%	15	%

Note 11: 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 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. Additionally such agreements require HFC to reimburse us for certain costs. As of December 31, 2012, these agreements with HFC will result in minimum annualized payments to us of $217.2 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 these agreements, a shortfall payment may be applied as a credit in the following four quarters after its minimum obligations are met.

In November 2011, we reached an agreement with HFC that clarifies certain terms of a crude pipelines and tankage throughput agreement, whereby HFC agreed to pay us $5.5 million for certain past deliveries on our crude pipeline system. We recognized this settlement as revenue in the fourth quarter of 2011 that will be billed in six equal quarterly installments through March 2013.

Under certain provisions of an omnibus agreement we have with HFC (the "Omnibus Agreement") we pay HFC an annual administrative fee for the provision by HFC or its affiliates of various general and administrative services to us, currently $2.3 million. This fee does not include the salaries of personnel employed by HLS who perform services for us 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 $245.6 million, $168.3 million and $146.4 million for the years ended December 31, 2012, 2011 and 2010, respectively.
- HFC charged us general and administrative services under the Omnibus Agreement of $2.3 million for each of the three years ended December 31, 2012, 2011 and 2010.
- We reimbursed HFC for costs of employees supporting our operations of $31.1 million, $21.4 million and $18.6 million for the years ended December 31, 2012, 2011 and 2010, respectively.
- HFC reimbursed us $13.4 million, $11.9 million and $3.7 million for the years ended December 31, 2012, 2011 and 2010, respectively, for certain reimbursable costs and capital projects.
- We distributed $64.0 million, $40.6 million and $35.9 million, for the years ended December 31, 2012, 2011 and 2010, respectively, to HFC as regular distributions on its common units and general partner interest, including general partner incentive distributions.
- Accounts receivable from HFC were $31.6 million and $31.9 million at December 31, 2012 and 2011, respectively.
- Accounts payable to HFC were $5.0 million and $6.5 million at December 31, 2012 and 2011, respectively.
- Revenues for the years ended December 31, 2012, 2011 and 2010 include $7.8 million, $3.3 million and $3.6 million of shortfall payments billed in 2011, 2010 and 2009, respectively, as HFC did not exceed its minimum volume commitment in any of the subsequent four quarters in 2012, 2011 and 2010. Additionally revenues for the year ended December 31, 2012 include $3.8 million due to capacity constraints on our UNEV pipeline system. Deferred revenue in the consolidated balance sheets at December 31, 2012 and 2011, includes $5.1 million and $4.0 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 $5.1 million deferred at December 31, 2012.
- We acquired from HFC a 75% interest in the UNEV Pipeline in July 2012 and certain tankage and terminal assets in November 2011 and March 2010. See Note 3 for a description of these transactions.

Note 12: Partners' Equity, Income Allocations and Cash Distributions

As of December 31, 2012, HFC held 24,255,030 of our common units and the 2% general partner interest, which together constituted a 44% ownership interest in us.

On November 29, 2012, we announced a two-for-one unit split, payable in the form of a common unit distribution for each issued and outstanding common unit. The unit distribution was paid January 16, 2013 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 periods presented.

Common Unit Issuances

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.

2011 Issuances
We issued in a public offering 2,950,000 of our common units priced at $26.75 per unit in December 2011. Aggregate net proceeds of $75.8 million were used to pay a portion of outstanding principal of the Promissory Notes.

We issued 7,615,230 of our common units to HFC in November 2011 as partial consideration for the purchase of certain tankage, loading rack and crude receiving assets located at HFC's El Dorado and Cheyenne refineries.

We received aggregate capital contributions of $5.9 million from our general partner to maintain its 2% general partner interest concurrent with the 2011 common unit issuances described above.

Under our registration statement filed with the SEC using a “shelf” registration process, we currently have the ability to raise up to $2 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.

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,		
	2012	2011	2010
	(in thousands)		
General partner interest in net income	$1,464	$1,287	$903
General partner incentive distribution	20,986	15,519	11,181
Total general partner interest in net income	$22,450	$16,806	$12,084

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 24, 2013 we announced our cash distribution for the fourth quarter of 2012 of $0.47 per unit. The distribution is payable on all common and general partner units and will be paid February 14, 2013 to all unitholders of record on February 4, 2013.

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,		
	2012	2011	2010
	(In thousands, except per unit data)		
General partner interest	$2,566	$1,981	$1,724
General partner incentive distribution	20,986	15,519	11,181
Total general partner distribution	23,552	17,500	12,905
Limited partner distribution	102,222	81,508	73,223
Total regular quarterly cash distribution	$125,774	$99,008	$86,128
Cash distribution per unit applicable to limited partners	$1.835	$1.740	$1.660

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 of $305.6 million, exclusive of depreciation and amortization, would have been recorded in our financial statements, as increases to our properties and equipment and intangible assets instead of decreases to our partners' equity.

Note 13: 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, 2012 [(1)]					
Revenues	$68,415	$68,660	$74,054	$81,431	$292,560
Operating income	$31,602	$30,116	$35,572	$40,973	$138,263
Income before income taxes	$19,431	$19,204	$23,909	$28,932	$91,476
Net income	$19,356	$19,128	$23,773	$28,848	$91,105
Net income attributable to Holly Energy Partners	$21,774	$22,003	$23,336	$27,039	$94,152
Limited partners' per unit interest in net income – basic and diluted	$0.30	$0.30	$0.32	$0.37	$1.29
Distributions per limited partner unit	$0.448	$0.455	$0.462	$0.470	$1.835
Year Ended December 31, 2011 [(1)]					
Revenues	$45,122	$50,908	$49,151	$69,087	$214,268
Operating income	$22,262	$26,648	$20,598	$36,705	$106,213
Income before income taxes	$14,441	$18,391	$12,431	$27,560	$72,823
Net income	$14,213	$18,373	$12,508	$27,495	$72,589
Net income attributable to Holly Energy Partners	$14,600	$18,673	$15,632	$30,894	$79,799
Limited partners' per unit interest in net income – basic and diluted	$0.25	$0.34	$0.26	$0.51	$1.38
Distributions per limited partner unit	$0.428	$0.433	$0.438	$0.443	$1.740

(1) Prior period amounts have been revised. See Note 2 for additional information. The table below outlines the impact of such corrections on quarterly limited partners' interest in net income. Other differences in amounts previously reported relate to the acquisitions as discussed in Notes 2 and 3.

	First	Second	Third	Fourth	Total
	Increase (Decrease)				
	(In thousands, except per unit data)				
Year Ended December 31, 2012					
Net income attributable to Holly Energy Partners	$(205)	$(1,159)	$(1,157)	$—	$—
Limited partners' per unit interest in net income – basic and diluted	$—	$(0.02)	$(0.02)	$—	$—
Year Ended December 31, 2011					
Net income attributable to Holly Energy Partners	$(569)	$(339)	$(1,112)	$48	$(1,972)
Limited partners' per unit interest in net income – basic and diluted	$(0.01)	$—	$(0.03)	$—	$(0.04)

Note 14: 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 wholly-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 and the Guarantor Subsidiaries. The information has been presented as if the Parent accounted for its ownership in the Guarantor Subsidiaries using the equity method of accounting.

Prior period amounts have been recast to include UNEV operations acquired July 12, 2012, as if it had been acquired March 1, 2008, the date we were under common control with HFC. The tankage, loading rack and crude receiving assets located at HFC's El Dorado and Cheyenne refineries acquired on November 9, 2011 were recast as if they had been acquired on July 1, 2011, the date upon which HFC obtained control of such assets. This treatment is required under GAAP as the transactions were between entities under common control. Additionally, we corrected certain amounts previously reported in 2011 and 2010. See Note 2 for additional information.

Condensed Consolidating Balance Sheet

December 31, 2012	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Current assets:					
Cash and cash equivalents	$2	$823	$ 4,412	$—	$5,237
Accounts receivable	—	32,319	6,401	—	38,720
Intercompany accounts receivable (payable)	42,194	(42,194)	—	—	—
Prepaid and other current assets	224	2,395	1,000	—	3,619
Total current assets	42,420	(6,657)	11,813	—	47,576
Properties and equipment, net	—	563,701	396,834	—	960,535
Investment in subsidiaries	777,472	300,607	—	(1,078,079)	—
Transportation agreements, net	—	94,596	—	—	94,596
Goodwill	—	256,498	—	—	256,498
Investment in SLC Pipeline	—	25,041	—	—	25,041
Other assets	1,154	8,710	—	—	9,864
Total assets	$821,046	$1,242,496	$ 408,647	$(1,078,079)	$1,394,110
LIABILITIES AND PARTNERS' EQUITY					
Current liabilities:					
Accounts payable	$—	$10,745	$ 1,285	$—	$12,030
Accrued interest	10,198	28	—	—	10,226
Deferred revenue	—	3,319	5,582	—	8,901
Accrued property taxes	—	1,923	765	—	2,688
Other current liabilities	563	1,274	68	—	1,905
Total current liabilities	10,761	17,289	7,700	—	35,750
Long-term debt	443,674	421,000	—	—	864,674
Other long-term liabilities	55	15,241	137	—	15,433
Deferred revenue	—	11,494	—	—	11,494
Class B unit	13,903	—	—	—	13,903
Equity - partners	352,653	777,472	400,810	(1,178,282)	352,653
Equity - noncontrolling interest	—	—	—	100,203	100,203
Total liabilities and partners' equity	$821,046	$1,242,496	$ 408,647	$(1,078,079)	$1,394,110

Condensed Consolidating Balance Sheet

December 31, 2011	Parent	Guarantor Restricted Subsidiaries	Non-Guarantor Non-Restricted Subsidiaries	Eliminations	Consolidated
	(In thousands)				
ASSETS					
Current assets:					
Cash and cash equivalents	$2	$3,267	$ 3,100	$—	$6,369
Accounts receivable	—	33,972	4,080	—	38,052
Intercompany accounts receivable (payable)	17,745	(17,745)	—	—	—
Prepaid and other current assets	266	2,378	1,085	—	3,729
Total current assets	18,013	21,872	8,265	—	48,150
Properties and equipment, net	—	559,212	401,287	—	960,499
Investment in subsidiaries	960,516	297,008	—	(1,257,524)	—
Transportation agreements, net	—	101,543	—	—	101,543
Goodwill	—	256,498	—	—	256,498
Investment in SLC Pipeline	—	25,302	—	—	25,302
Other assets	1,322	5,882	—	—	7,204
Total assets	$979,851	$1,267,317	$ 409,552	$(1,257,524)	$1,399,196
LIABILITIES AND PARTNERS' EQUITY					
Current liabilities:					
Accounts payable	$—	$11,307	$ 13,542	$—	$24,849
Accrued interest	7,498	782	—	—	8,280
Deferred revenue	—	4,447	—	—	4,447
Accrued property taxes	—	2,196	—	—	2,196
Other current liabilities	689	1,088	—	—	1,777
Total current liabilities	8,187				