HOLLY ENERGY PARTNERS LP
Form 10-K
February 24, 2012

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE

SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2011

Commission File Number 1-32225

HOLLY ENERGY PARTNERS, L.P.

Formed under the laws of the State of Delaware

I.R.S. Employer Identification No. 20-0833098

2828 N. Harwood, Suite 1300

Dallas, Texas 75201-1507

Telephone Number: (214) 871-3555

Securities registered pursuant to Section 12(b) of the Act:

Common Limited Partner Units

Securities registered pursuant to Section 12(g) of the Act:

None

Indicate by check mark whether the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x 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 x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x 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 amendments 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 definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer	x	Accelerated filer	¨
Non-accelerated filer	¨	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 x

The aggregate market value of common limited partner units held by non-affiliates of the registrant was approximately $800 million on June 30, 2011, based on the last sales price as quoted on the New York Stock Exchange.

The number of the registrant s outstanding common limited partners units at February 16, 2012 was 27,361,124.

DOCUMENTS INCORPORATED BY REFERENCE: None

TABLE OF CONTENTS

PART I

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains certain forward-looking statements within the meaning of the federal securities laws. All statements, other than statements of historical fact included in this Form 10-K, including, but not limited to, those under Business , Risk Factors and Properties in Items 1, 1A and 2 and Management s Discussion and Analysis of Financial Condition and Results of Operations in Item 7, are forward-looking statements. Forward looking statements use words such as anticipate, project, expect, plan, goal, forecast, intend, co believe, 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. Such 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 and tanks;
- 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, terminal and tankage 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, operations 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 risk factors and other cautionary statements set forth in this Form 10-K under Risk Factors in Item 1A. All forward-looking statements included in this Form 10-K and all subsequent written or oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements. The forward-looking statements speak only as of the date made and, other than as required by law, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

INDEX TO DEFINED TERMS AND NAMES

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

Terms used in the financial statements and footnotes are as defined therein

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, 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 Corporate 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 (formerly known as Holly 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. HFC changed its name in connection with the consummation of its merger of equals with Frontier Oil Corporation effective July 1, 2011.

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 42% interest in us, including the 2% general partner interest. Additionally, 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 directly exposed to changes in commodity prices.

Our assets include:

Pipelines:

- approximately 820 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; and

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

Refined Product Terminals and Refinery Tankage:

- four refined product terminals located in El Paso, Texas; Moriarty and Bloomfield, New Mexico; and Tucson, Arizona, with an aggregate capacity of approximately 1,000,000 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 480,000 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 east 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 1,400,000 barrels; and
- on-site refined and intermediate product tankage at HFC s Tulsa, Cheyenne and El Dorado refineries having an aggregate storage capacity of approximately 8,300,000 barrels;

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

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 3,807,615 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 $47 million.

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.

2009 Acquisitions

Sinclair Logistics and Storage Assets Transaction

On December 1, 2009, we acquired from Sinclair Oil Company (Sinclair) storage tanks having approximately 1.4 million barrels of storage capacity and loading racks at its refinery located in Tulsa, Oklahoma for $79.2 million. The purchase price consisted of $25.7 million in cash, including $4.2 million in taxes paid and 1,373,609 of our common units having a fair value of $53.5 million. Separately, HFC, also a party to the transaction, acquired Sinclair s Tulsa refinery.

Roadrunner / Beeson Pipelines Transaction

Also on December 1, 2009, we acquired from HFC two newly constructed pipelines for $46.5 million, consisting of a 65-mile, 16-inch crude oil pipeline (the Roadrunner Pipeline) that connects the Navajo refinery Lovington facility to a terminus of Centurion Pipeline L.P. s pipeline extending between west Texas and Cushing, Oklahoma and a 37-mile, 8-inch crude oil pipeline that connects our New Mexico crude oil gathering system to the Navajo refinery Lovington facility (the Beeson Pipeline).

Tulsa West Loading Racks Transaction

On August 1, 2009, we acquired from HFC certain truck and rail loading/unloading facilities located at HFC s Tulsa refinery west facility for $17.5 million. The racks load refined products and lube oils produced at the Tulsa refinery onto rail cars and/or tanker trucks.

Lovington-Artesia Pipeline Transaction

On June 1, 2009, we acquired from HFC a newly constructed, 16-inch intermediate pipeline for $34.2 million that runs 65 miles from the Navajo refinery s crude oil distillation and vacuum facilities in Lovington, New Mexico to its petroleum refinery located in Artesia, New Mexico.

SLC Pipeline Joint Venture Interest

On March 1, 2009, we acquired a 25% joint venture interest in the SLC Pipeline, a 95-mile intrastate pipeline system that we jointly own with Plains. The total cost of our investment in the SLC Pipeline was $28 million, consisting of the capitalized $25.5 million joint venture contribution and the $2.5 million finder s fee paid to HFC that was expensed as acquisition costs.

HFC Capacity Expansion

Also in March 2009, HFC, our largest customer, completed a 15,000 barrels per stream day (bpsd) capacity expansion of its Navajo refinery increasing refining capacity to 100,000 bpsd, or by 18%.

Rio Grande Pipeline Sale

On December 1, 2009, we sold our 70% interest in Rio Grande Pipeline Company (Rio Grande) to a subsidiary of Enterprise Products Partners LP for $35 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. As of December 31, 2011, these agreements with HFC will result in minimum annualized payments to us of $192 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. Also, 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, 2011, these agreements with Alon will result in minimum annualized payments to us of $30 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.

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 pipeline and terminal personnel 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 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, special 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 2012 capital budget is comprised of $8.9 million for maintenance capital expenditures and $25.8 million for expansion capital expenditures.

We recently have made certain modifications to our crude oil gathering and trunk line system that have effectively 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. Furthermore, we have developed a project to replace a 5-mile section of this pipeline system that will allow for an additional 15,000 bpd of capacity that will be executed as needed if Delaware Basin crude volumes continue to increase. This project is estimated to cost approximately $2 million. We have a second project which consists of the reactivation and conversion to crude oil service of a 70-mile, 8-inch petroleum products pipeline owned by us. Once in service, this pipeline will initially be capable of transporting up to 35,000 bpd of crude oil from southeast New Mexico to third-party common carrier pipelines in west Texas for further transport to major crude oil markets. The scope of this project is being finalized. Subject to receipt of acceptable shipper support and board approval, this project could be operational in early 2013.

We are in discussions with HFC regarding our option to purchase its 75% equity interest in UNEV Pipeline, LLC (the UNEV Pipeline), a joint venture pipeline that is capable of transporting refined petroleum products from Salt Lake City, Utah to Las Vegas, Nevada. The initial capacity of this pipeline is 62,000 bpd, with the capacity for further expansion to 120,000 bpd. The total construction cost of this pipeline, including terminals and ethanol blending and storage facilities, was approximately $410 million. HFC s share of the cost is $308 million. The pipeline was mechanically complete in November 2011, and initial start-up activities commenced in December 2011. We are not obligated to purchase the UNEV Pipeline nor are we subject to any fees or penalties if HLS board of directors decides not to proceed with this opportunity.

We expect that our currently planned sustaining and maintenance capital expenditures, as well as expenditures for acquisitions and capital development projects such as our option to purchase HFC s interest in the UNEV Pipeline described above, 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 $375 million senior secured credit agreement expiring in February 2016 (the Amended 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 Amended Credit Agreement, our ability to fund some of these capital projects may be limited, especially the UNEV Pipeline.

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. They also 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 are also protected by foam systems that are activated in case of fire. All of our terminals are subject to participation in a comprehensive environmental management program to assure compliance with applicable air, solid waste, and wastewater regulations.

COMPETITION

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

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

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

In addition, we face competition from trucks that deliver product in a number of areas we serve. Although their costs may not be competitive for longer hauls or large volume shipments, trucks compete effectively for incremental and marginal volumes in many areas we serve. The availability of truck transportation places some competitive constraints on us.

Historically, the significant majority of the throughput at our terminal facilities has come from HFC, with the exception of third-party receipts at the Spokane terminal, Alon volumes at El Paso, and the Abilene and Wichita Falls terminals that serve Alon s Big Springs refinery.

Our ten refined product terminals compete with other independent terminal operators as well as integrated oil companies based on terminal location, price, versatility and services provided. Our competition primarily comes from integrated petroleum companies, refining and marketing companies, independent terminal companies and distribution companies with marketing and trading arms.

RATE REGULATION

Some of our existing pipelines are subject to rate regulation by the FERC under the Interstate Commerce Act. The Interstate Commerce Act requires that tariff rates for oil pipelines, a category that includes crude oil and petroleum product pipelines, be just and reasonable and 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 have generally 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 with HFC, HFC has agreed to indemnify us, subject to certain limitations, for environmental noncompliance and remediation liabilities associated with assets transferred to us from HFC and occurring or existing prior to the date of such transfers. The Omnibus Agreement provides environmental indemnification with respect to certain transferred assets of up to $15 million through 2021, plus additional indemnification of $2.5 million through 2015 and up to $7.5 million through 2023. HFC s indemnification obligations under the Omnibus Agreement do not apply to (i) the Tulsa west loading racks acquired in August 2009, (ii) the 16-inch intermediate pipeline acquired in June 2009, (iii) the Roadrunner Pipeline, (iv) the Beeson Pipeline, (v) the logistics and storage assets acquired from Sinclair in December 2009, or (vi) the Tulsa east storage tanks and loading racks acquired in March 2010. For the Tulsa loading racks acquired from HFC in August 2009 and the Tulsa logistics and storage assets acquired from Sinclair in December 2009, HFC agreed to indemnify us for environmental liabilities arising from our pre-ownership operations of these assets. Additionally, HFC agreed to indemnify us for any liabilities arising from its operation of our loading racks located at HFC s Tulsa refinery west facility.

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 through 2015, subject to a $100,000 deductible and a $20 million maximum liability cap.

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 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. Additionally, as of December 31, 2011, we have an accrual of $1 million that relates to environmental clean-up projects for which we have assumed liability. 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.

EMPLOYEES

Neither we nor our general partner has employees. Direct support for our operations is provided by HLS, which employs 216 people. Included in this number are 57 employees (40 of which are subject to collective bargaining agreements having various expiration dates) that were previously employed by HFC prior to our November 2011 acquisition of certain tankage and terminal assets located at HFC s El Dorado and Cheyenne refineries. 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 carefully consider the following risk factors 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

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, 2011, HFC accounted for 75% of the revenues of our petroleum product and crude pipelines and 87% of the revenues of our terminals 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, 2011, production from the Navajo refinery accounted for 83% 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:

- 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:
  - 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 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, 2011, Alon accounted for 18% 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 materially reduce 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 beyond the control of either of us, 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, 2011, the principal amount of our total outstanding debt was $608 million. Effective November 1, 2011, we issued promissory notes to HFC Corporation with an aggregate original principal amount of $150 million in connection with our acquisition of certain pipeline, tankage, loading rack and crude receiving assets located at HFC Corporation s El Dorado and Cheyenne refineries. 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 Amended Credit Agreement and the indentures for our 6.25% senior notes due 2015 and the 8.25% senior notes due 2018 (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.

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 Amended Credit Agreement to service our indebtedness. However, a significant downturn in our business or other development adversely affecting our cash flow could materially impair our ability to service our indebtedness. If our cash flow and capital resources are insufficient to fund our debt service obligations, we may be forced to refinance all or a portion of our debt or sell assets. We cannot 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 and the crude pipelines and tankage assets restrict us from selling these pipelines and terminals acquired from HFC and from prepaying borrowings and long-term debt to outstanding balances below $171 million prior to 2018, subject to certain limited exceptions. Our leverage may adversely affect our ability to fund future working capital, capital expenditures and other general partnership requirements, future acquisitions, construction or development activities, or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness or to comply with any restrictive terms of our indebtedness. Our leverage may also 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 most recently, low consumer confidence, continued 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 announced and future pipeline 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 and vendors.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. 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.

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 competitively supply our shippers end-user markets with refined products. The Longhorn Pipeline, owned by Magellan Midstream Partners, L.P., is an approximately 72,000 bpd common carrier pipeline that delivers refined products utilizing a direct route from the Texas Gulf Coast to El Paso and, through interconnections with third-party common carrier pipelines, into the Arizona market. Increased supplies of refined product delivered by the Longhorn Pipeline and 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 materially reduce our revenues.

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 caused 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. Alon s obligations to lease capacity on the Artesia-Orla-El Paso pipeline have remaining terms that expire beginning in 2018 through 2022. 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 also adversely 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 affect on our business from increased regulation of our facilities.

Recently enacted pipeline safety legislation, 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.

Significant physical effects of climate change have the potential to damage our facilities, disrupt our operations and cause us to incur significant costs in preparing for or responding to those effects.

Climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our operations could be adversely affected. Potential adverse effects could include damage to our facilities from severe weather such as powerful winds or rising waters in low-lying areas, disruption of our operations, either because of climate-related damage to our facilities or scale-backs in our operations due to the threat of such effects, and higher operating costs and less efficient or non-routine operating practices necessitated by potential climatic effects or in the aftermath of such effects. Significant physical effects of climate change could also affect us indirectly by disrupting the operations of our customers or by disrupting services or supplies provided by service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the costs that may result from potential physical effects of climate change.

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 have also 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. We are also 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.

Recently proposed rules regulating air emissions from oil and gas operations could cause us to incur increased capital expenditures and operating costs.

On July 28, 2011, the EPA proposed rules that would establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA s proposed rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The EPA s proposal would establish specific requirements regarding emissions from compressors, dehydrators, storage tanks, and other production-related equipment. The EPA will receive public comment and hold hearings regarding the proposed rules and must take final action on them by February 28, 2012. If finalized, these rules could require a number of modifications to our operations including the installation of new equipment. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

We may have additional maintenance costs in the future.

Our pipeline and storage assets are generally long-lived assets, and some of those assets have been in service for many years. The age and condition of these assets could result in increased maintenance or remediation expenditures. Any significant increase in these expenditures could adversely affect our results of operations, financial position or cash flows, as well as our ability to pay cash distributions. However, we maintain continuing monitoring programs and maintenance expenditures in an attempt to address such issues.

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.

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 may not allow us to recover the full amount of increases in our costs.

The FERC regulates the tariff rates for interstate movements on our pipeline systems. The primary rate-making methodology of the FERC is price indexing. We use this methodology in all of our interstate markets. The indexing method allows a pipeline to increase its rates based on a percentage change in the producer price index for finished goods. If the index falls, we will be required to reduce our rates that are based on the FERC s price indexing methodology if they exceed the new maximum allowable rate. 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 our interstate or intrastate tariff rates are successfully challenged, we could be required to reduce our tariff rates, which would reduce our revenues.

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 could also 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.

Potential changes to current petroleum pipeline rate-making methods and procedures may impact the federal and state regulations under which we will operate in the future.

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. If the FERC s petroleum pipeline rate-making methodology changes, the new methodology could result in tariffs that generate lower revenues and cash flow. Furthermore, competition from other pipeline systems may prevent us from raising our tariff rates even if regulatory agencies permit us to do so.

The fees we charge to third parties under transportation and storage agreements may not escalate sufficiently to cover increases in our costs, and the agreements may not be renewed or may be suspended in some circumstances.

Our costs may increase at a rate greater than the rate that the fees we charge to third parties increase pursuant to our contracts with them. Furthermore, third parties may not renew their contracts with us. Additionally, some third parties obligations under their agreements with us may be permanently or temporarily reduced upon the occurrence of certain events, some of which are beyond our control, including force majeure events wherein the supply of crude oil or refined products is curtailed or cut off. Force majeure events include (but are not limited to) revolutions, wars, acts of enemies, embargoes, import or export restrictions, strikes, lockouts, fires, storms, floods, acts of God, explosions and mechanical or physical failures of our equipment or facilities or those of third parties. If the escalation of fees is insufficient to cover increased costs, if third parties do not renew or extend their contracts with us or if any third party suspends or terminates its contracts with us, our financial results would be negatively impacted.

Terrorist attacks, and the threat of terrorist attacks or domestic vandalism, have resulted in increased costs to our business. Continued hostilities in the Middle East 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 hostilities in the Middle East 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 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 Amended 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 adversely affect 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.

Alternative financing strategies may not be successful.

Periodically, we will consider the use of alternative financing strategies such as joint venture arrangements and the sale of non-strategic assets. Joint venture agreements may not share the risks and rewards of ownership in proportion to the voting interests. Joint venture arrangements may require us to pay certain costs or to make certain capital investments and we may have little control over the amount or the timing of these payments and investments. We may not be able to negotiate terms that adequately reimburse us for our costs to fulfill service obligations for those joint ventures where we are the operator. In addition, our joint venture partners may be unable to meet their economic or other obligations and we may be required to fulfill those obligations alone.

We may periodically sell assets or portions of our business. Separating the existing operations from our assets or operations of which we dispose may result in significant expense and accounting charges, disrupt our business or divert management s time and attention. We may not achieve expected cost savings from these dispositions or the proceeds from sales of assets or portions of our business may be lower than the net book value of the assets sold. We may not be relieved of all of our obligations related to the assets or businesses sold. These factors could have a material adverse effect on our revenues, income from operations, cash flows and our quarterly distribution on our common units.

Ongoing maintenance of effective internal controls in accordance with Section 404 of the Sarbanes-Oxley Act could cause us to incur additional expenditures of time and financial resources.

We regularly document and test our internal control procedures in order to satisfy the requirements of Section 404 of the Sarbanes-Oxley Act, which requires annual management assessments of the effectiveness of our internal controls over financial reporting and a report by our independent registered public accounting firm on our controls over financial reporting. If, in the future, we fail to maintain the adequacy of our internal controls, as such standards are modified, supplemented or amended from time to time; we may not be able to ensure that we can conclude on an ongoing basis that we have effective internal controls over financial reporting in accordance with Section 404 of the Sarbanes-Oxley Act. Failure to achieve and maintain an effective internal control environment could cause us to incur substantial expenditures of management time and financial resources to identify and correct any such failure.

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 2011 we completed the El Dorado and Cheyenne tankage and terminal 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 2011. Also, following an acquisition, we may discover previously unknown liabilities associated with the acquired business or assets for which we have no recourse under applicable indemnification provisions.

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

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

- denial or delay in issuing requisite regulatory approvals and/or permits;
- unplanned increases in the cost of construction materials or labor;
- disruptions in transportation of modular components and/or construction materials;
- severe adverse weather conditions, natural disasters, or other events (such as equipment malfunctions explosions, fires, 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 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 a result of our acquisition of certain assets of HFC s El Dorado and Cheyenne refineries in November 2011, as of December 31, 2011, approximately 20% 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.

In certain cases we have the right to be indemnified by third parties for environmental liabilities, and our results of operation and our ability to make distributions to our unitholders could be adversely affected if a third party fails to satisfy an indemnification obligation owed to us.

In connection with the pipelines, terminals and tanks transferred to us by HFC in connection with our initial public offering in 2004, the intermediate pipelines acquired in 2005, the crude pipelines and tankage assets acquired in 2008, the asphalt loading rack facility acquired in March 2010, and the refined product pipelines, tankage and terminals acquired from Alon in 2005, we have entered into environmental agreements with them pursuant to which they have agreed to indemnify us for certain pre-closing environmental liabilities discovered within specified time periods after the date of the applicable acquisition. These indemnities continue through 2014 for the assets contributed to us by HFC at our initial public offering, through 2015 for the intermediate pipelines acquired from HFC and the refined product pipelines, tankage and terminals acquired from Alon, and through 2023 for the crude pipelines and tankage assets acquired from HFC. Additionally, we have entered into agreements with HFC in connection with our acquisition of the Sinclair Logistics Assets and the Tulsa Loading Racks that provide that HFC will indemnify us for certain matters arising from the pre-closing ownership or operation of these assets, which indemnification obligations are not time limited. Other third parties are also obligated to indemnify us for ongoing remediation pursuant to separate indemnification obligations. Our results of operation and our ability to make cash distributions to our unitholders could be adversely affected in the future if HFC, Alon, or other third parties fail to satisfy an indemnification obligation owed to us.

Many of our executive officers face conflicts in the allocation of their time to our business.

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 are also 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 adversely affect our results of operations, cash flows and financial condition.

RISKS TO COMMON UNITHOLDERS

HFC and its affiliates 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 40% 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;

- 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 our general partner and its affiliates for services provided, are substantial.

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 will be properly 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.

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.

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 the Partnership currently has a shelf registration on file with the SEC pursuant to which it may issue up to $781 million 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 11,097,615 of our common units, which is approximately 40% 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. As long as we qualify to be treated as a partnership for federal income tax purposes, we are not subject to federal income tax. Although a publicly-traded limited partnership is generally treated as a corporation for federal income tax purposes, a publicly-traded partnership such as us can qualify to be treated as a partnership for federal income tax purposes so long as for each taxable year at least 90% of its gross income is derived from specified investments and activities. We believe that we qualify to be treated as a partnership for federal income tax purposes because we believe that at least 90% of our gross income for each taxable year has been and is derived from such specified investments and activities. While we intend to meet this gross income requirement, regardless of our efforts we may not find it possible to meet, or may inadvertently fail to meet, this gross income requirement. If we do not meet this gross income requirement for any taxable year and the IRS does not determine that such failure was inadvertent, we would be treated as a corporation for such taxable year and each taxable year thereafter. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

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.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation, possibly on a retroactive basis. At the federal level, members of Congress have recently considered substantive changes to existing federal income tax laws that would affect the tax treatment of certain publicly traded partnerships. We are unable to predict whether any of these potential changes, or other proposals, will ultimately be enacted into law. Any such changes could negatively impact the value of an investment in our common units. At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of such a tax on us by Texas and, if applicable, by any other state will reduce the cash available for distribution to unitholders.

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

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.

Our partnership agreement allows remedial allocations of income, deduction, gain and loss by us to account for differences between the tax basis and fair market value of property at the time the property is contributed or deemed contributed to us and to account for differences between the fair market value and book basis of our assets existing at the time of issuance of any common units. If the IRS does not respect our remedial allocations, ratios of taxable income to cash distributions received by the holders of common units will be materially higher than previously estimated.

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. A unitholder s amount realized will be measured by the sum of the cash and the fair market value of other property, if any, received by the unitholder, plus its share of our nonrecourse liabilities. Because the amount realized will include the unitholder s share of our nonrecourse liabilities, the gain recognized by the unitholder on the sale of its units could result in a tax liability in excess of any cash it receives from the sale. Distributions in excess of a unitholder s allocable share of our net taxable income (excess distributions) decrease the unitholder s tax basis in its common units, which includes its share of nonrecourse liabilities. Such excess distributions with respect to the units sold 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 items, including depreciation recapture.

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 and in order to maintain the uniformity of the economic and tax characteristics of our common units, we have adopted depreciation and amortization positions that may not conform to all aspects of existing treasury regulations. These positions may result in an understatement of deductions and losses and an overstatement of income and gain to our unitholders. For example, we do not amortize certain goodwill assets, the value of which has been attributed to certain of our outstanding common units. A subsequent holder of those common units is entitled to an amortization deduction attributable to that goodwill under Internal Revenue Code Section 743(b). However, because we cannot identify these common units once they are traded by the initial holder, we do not give any subsequent holder of a common unit any such amortization deduction. This approach may understate deductions available to those unitholders who own those common units and may result in those unitholders reporting that they have a higher tax basis in their units than would be the case if the IRS strictly applied treasury regulations relating to these depreciation or amortization adjustments. This, in turn, may result in those unitholders reporting less gain or more loss on a sale of their units than would be the case if the IRS strictly applied those treasury regulations.

The IRS may challenge the manner in which we calculate our unitholder s basis adjustment under Internal Revenue Code Section 743(b). If so, because neither we nor a unitholder can identify the common units to which an issue relates once the initial holder has traded them, the IRS may assert adjustments to all unitholders selling common units within the period under audit as if all unitholders owned common units with respect to which allowable deductions were not taken. Any position we take that is inconsistent with applicable treasury regulations may have to be disclosed on our federal income tax return. This disclosure increases the likelihood that the IRS will challenge our positions and propose adjustments to some or all of our unitholders. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to a unitholder. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to a unitholder s 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 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. Accordingly, our counsel is unable to opine on the validity of this method. 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 loaned 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 a unitholder whose units are loaned to a short seller to cover a short sale of units may be considered as having disposed of the loaned units, such unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We may adopt 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 reporting of partnership tax information is complicated and subject to audits.

We furnish each unitholder with a Schedule K-1 that sets forth the unitholder s share of our income, gains, losses and deductions. We cannot guarantee that these schedules will be prepared in a manner that conforms in all respects to statutory or regulatory requirements or to administrative pronouncements of the IRS. Further, our tax return may be audited, which could result in an audit of a unitholder s individual tax return and increased liabilities for taxes because of adjustments resulting from the audit.

There are limits on the deductibility of our losses that may adversely affect our unitholders.

There are a number of limitations that may prevent unitholders from using their allocable share of our losses as a deduction against unrelated income. In cases when our unitholders are subject to the passive loss rules (generally, individuals and closely-held corporations), any losses generated by us will only be available to offset our future income and cannot be used to offset income from other activities, including other passive activities or investments. Unused losses may be deducted when the unitholder disposes of its entire investment in us in a fully taxable transaction with an unrelated party. A unitholder s share of our net passive income may be offset by unused losses from us carried over from prior years, but not by losses from other passive activities, including losses from other publicly traded partnerships. Other limitations that may further restrict the deductibility of our losses by a unitholder include the at-risk rules and the prohibition against loss allocations in excess of the unitholder s tax basis in its units.

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

We will be considered to have terminated our partnership for federal income tax purposes if there 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 recently 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 will likely be subject to state and local taxes and return filing requirements as a result of investing in our common units.

In addition to federal income taxes, unitholders will likely 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. 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. 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 and Washington. 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.

Unitholders may have negative tax consequences if we default on our debt or sell assets.

If we default on any of our debt, our lenders will have the right to sue us for non-payment. Such an action could cause an investment loss and cause negative tax consequences for unitholders through the realization of taxable income by unitholders without a corresponding cash distribution. Likewise, if we were to dispose of assets and realize a taxable gain while there is substantial debt outstanding and proceeds of the sale were applied to the debt, unitholders could have increased taxable income without a corresponding cash distribution.

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. 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 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 provided in the pipelines and terminal agreements with HFC and Alon, 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,				
	2011	2010	2009	2008	2007
Volumes transported for (bpd):					
HFC	345,990	324,382	295,039	253,484	142,447
Third parties[1]	52,361	38,910	43,709	22,756	46,511
Total	398,351	363,292	338,748	276,240	188,958
Total barrels in thousands (mbbls[1])	145,398	132,602	123,643	101,104	68,970

(1) We sold our 70% interest in Rio Grande on December 1, 2009. Rio Grande volumes are 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)	Approximate Length (miles)	Capacity (bpd)
Refined Product Pipelines:			
Artesia, NM to El Paso, TX	6	156	24,000
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	45,000(3)
Moriarty, NM to Bloomfield, NM(2)	8	191	(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
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	80,000
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 2011. These pipelines transported 90% of the light refined products produced by HFC s Navajo refinery in 2011.

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 and 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, 10-mile and a 12-inch, 72-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.

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 from the Navajo refinery Artesia facility to White Lakes Junction, New Mexico that was constructed in 1999, and approximately 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. We currently pay a monthly fee (which is subject to adjustments based on changes in the PPI) of $536,000 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.

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 only 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. Terminals play a key role in moving product to the end-user market by providing the following services:

distribution;

blending to achieve specified grades of gasoline;

other ancillary services that include the injection of additives and filtering of jet fuel; and

storage and inventory management.

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

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

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

	Years Ended December 31,				
	2011	2010	2009	2008	2007
Refined products terminalled for (bpd):					
HFC	193,645	178,903	114,431	109,539	119,910
Third parties	44,454	39,568	42,206	32,737	45,457
Total	238,099	218,471	156,637	142,276	165,367
Total (mbbls)	86,906	79,742	57,173	52,073	60,344

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	127,000	5	Pipeline	Truck/Pipeline
Wichita Falls, TX	220,000	11	Pipeline	Truck/Pipeline
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	2,471,000			

(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.

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 89% of the volumes at this terminal. We also receive product from the Big Spring refinery that accounted for 11% of the volumes at this terminal in 2011. 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) and a terminal connected to the Longhorn Pipeline.

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 Transportation Company (Sinclair Transportation) each own a 50% interest in the Boise terminal. Sinclair Transportation 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 Transportation each own a 50% interest in the Burley terminal. Sinclair Transportation 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 the Big Spring refinery, which accounted for all of its volumes in 2010. 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 Big Spring refinery, which accounted for all of its volumes in 2010. 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.

Roswell Terminal

This terminal receives jet fuel from the Navajo refinery, which accounted for all of its volumes in 2010, 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 the Big Spring refinery that accounted for all of its volumes in 2010. 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 9,700,000 barrels of storage.

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

Refinery Location	**Storage Capacity (barrels)**	**Tankage Type**	**Number of Tanks**
Artesia , NM	166,000	Crude oil	2

Lovington, NM	267,000	Crude oil	2
Woods Cross, UT	180,000	Crude oil	3
Tulsa, OK	3,485,000	Crude oil and refined product	59
Cheyenne, WY	1,842,000	Refined and intermediate product	58
El Dorado, KS	3,783,000	Refined and intermediate product	90
Total	9,723,000		

TRUCK FLEET

We have a truck fleet consisting of 7 trucks and 13 trailers that transport crude oil to HFC s Wood Cross refinery. Our trucking operations are conducted in Utah only, and HFC is our only customer.

PIPELINE AND TERMINAL CONTROL OPERATIONS

All of our pipelines are operated via geosynchronous satellite, microwave, radio and frame relay communication systems from our central control room located in Artesia, New Mexico. We also monitor activity at our terminals from this control room.

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

Item 3. Legal Proceedings

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

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for the Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Common Units

Our common limited partner units are traded on the New York Stock Exchange under the symbol HEP. The following table sets forth the range of the daily high and low sales prices per common unit, cash distributions to common unitholders and the trading volume of common units for the period indicated.

Years Ended December 31,	High	Low	Cash Distributions(1)	Trading Volume
2011				
Fourth quarter	$ 59.96	$ 47.30	$ 0.885	3,304,900
Third quarter	$ 55.02	$ 45.40	$ 0.875	2,025,400
Second quarter	$ 58.91	$ 48.55	$ 0.865	2,890,900
First quarter	$ 61.05	$ 50.12	$ 0.855	2,337,600
2010				
Fourth quarter	$ 53.74	$ 49.16	$ 0.845	2,530,800
Third quarter	$ 52.16	$ 42.17	$ 0.835	4,120,000
Second quarter	$ 48.17	$ 38.41	$ 0.825	4,945,100
First quarter	$ 44.95	$ 38.21	$ 0.815	4,583,200

(1) Represents cash distributions attributable to each of the quarters in the years ended December 31, 2011 and 2010. Distributions are declared and paid within 45 days following the close of each quarter.

The cash distribution for the fourth quarter of 2011 was declared on January 25, 2012 and is payable on February 14, 2012 to all unitholders of record on February 6, 2012.

As of February 16, 2012, we had approximately 13,000 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 Amended 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	$0.50	98%	2%
First target distribution	Up to $0.55	98%	2%
Second target distribution	above $0.55 up to $0.625	85%	15%
Third target distribution	above $0.625 up to $0.75	75%	25%
Thereafter	Above $0.75	50%	50%

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,				
	2011[1]	**2010**	**2009**	**2008**	**2007**
	(In thousands, except per unit data)				
Statement Of Income Data:					
Revenues	$ 213,549	$ 182,097	$ 146,561	$ 108,822	$ 96,190
Operating costs and expenses					
Operations	62,202	52,947	44,003	38,920	30,467
Depreciation and amortization	33,150	30,682	26,714	21,937	12,920
General and administrative	6,576	7,719	7,586	6,380	4,914
	101,928	91,348	78,303	67,237	48,301
Operating income	111,621	90,749	68,258	41,585	47,889
Equity in earnings of SLC Pipeline	2,552	2,393	1,919		
SLC Pipeline acquisition costs			(2,500)		
Interest income		7	11	118	454
Interest expense	(35,959)	(34,001)	(21,501)	(21,763)	(13,289)
Gain on sale of assets				36	298
Other income	17	17	67	990	
	(33,390)	(31,584)	(22,004)	(20,619)	(12,537)
Income from continuing operations before income taxes	78,231	59,165	46,254	20,966	35,352
State income tax	(234)	(296)	(20)	(270)	(200)
Income from continuing operations	77,997	58,869	46,234	20,696	35,152
Income from discontinued operations, net of noncontrolling interest[2]			19,780	4,671	4,119
Net income	77,997	58,869	66,014	25,367	39,271
Less general partner interest in net income, including incentive distributions[3]	16,769	12,152	7,947	3,913	3,166
Limited partners interest in net income	$ 61,228	$ 46,717	$ 58,067	$ 21,454	$ 36,105
Limited partners per unit interest in net income basic and diluted[3]	$ 2.68	$ 2.12	$ 3.18	$ 1.32	$ 2.24
Distributions per limited partner unit	$ 3.48	$ 3.32	$ 3.16	$ 3.00	$ 2.835
Other Financial Data:					
Cash flows from operating activities	$ 93,119	$ 103,168	$ 68,195	$ 63,651	$ 59,056
Cash flows from investing activities	$ (39,337)	$ (60,629)	$ (147,379)	$ (213,267)	$ (9,632)
Cash flows from financing activities	$ (50,916)	$ (44,644)	$ 76,423	$ 144,564	$ (50,658)
EBITDA[4]	$ 147,340	$ 123,841	$ 100,707	$ 70,195	$ 66,684
Distributable cash flow[5]	$ 100,295	$ 91,054	$ 72,213	$ 60,365	$ 51,012

Maintenance capital expenditures[5]	$ 5,415	$ 4,487	$ 3,595	$ 3,133	$ 1,863
Expansion capital expenditures	33,922	56,142	150,149	210,170	8,094
Total capital expenditures	$ 39,337	$ 60,629	$ 153,744	$ 213,303	$ 9,957
Balance Sheet Data (at period end):					
Net property, plant and equipment	$ 536,425	$ 434,950	$ 398,044	$ 257,886	$ 125,384
Total assets	$ 966,956	$ 643,273	$ 616,845	$ 439,688	$ 238,904
Long-term debt[6]	$ 605,888	$ 491,648	$ 390,827	$ 355,793	$ 181,435
Total liabilities	$ 637,579	$ 533,901	$ 422,981	$ 431,568	$ 200,348
Total equity[7]	$ 329,377	$ 109,372	$ 193,864	$ 8,120	$ 38,556

(1) We are a consolidated variable interest entity and under common control of HFC. With respect to the November 2011 tankage and terminal acquisition from HFC, GAAP requires that our financial statements reflect the historical operations of the assets recognized by HFC, effectively as if the assets were already under our ownership and control beginning July 1, 2011 (HFC s effective date of acquisition). Accordingly, we recognized an additional $2.3 million in operating costs and $1.4 million in depreciation expense for the year ended December 31, 2011 that relate to the operation of the assets for the period from July 1, 2011 through November 8, 2011, prior to our November 9, 2011 acquisition date. There are no revenues associated with these pre-acquisition expenses. Additionally, terminal and loading rack volume information does not reflect volumes prior to our acquisition date.

(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 U.S. generally accepted accounting principles (GAAP). However, the amounts included in the EBITDA calculation are derived from amounts included in our consolidated financial statements, with the exception of EBITDA from discontinued operations. EBITDA should not be considered as an alternative to net income or operating income, as an indication of our operating performance or as an alternative to operating cash flow as a measure of liquidity. EBITDA is not necessarily comparable to similarly titled measures of other companies. EBITDA is presented here because it is a widely used financial indicator used by investors and analysts to measure performance. EBITDA is also used by our management for internal analysis and as a basis for compliance with financial covenants.

Set forth below is our calculation of EBITDA.

	Years Ended December 31,				
	2011	**2010**	**2009**	**2008**	**2007**
			(In thousands)		
Income from continuing operations	$ 77,997	$ 58,869	$ 46,234	$ 20,696	$ 35,152
Add (subtract):					
Interest expense	34,706	30,453	20,620	18,479	12,281
Amortization of discount and deferred debt issuance costs	1,212	1,008	706	1,002	1,008
Increase in interest expense non-cash charges attributable to interest rate swaps and swap settlement costs	41	2,540	175	2,282	
Interest income		(7)	(11)	(118)	(454)
State income tax	234	296	20	270	200
Depreciation and amortization	33,150	30,682	26,714	21,937	12,920
EBITDA from discontinued operations (excludes gain on sale of Rio Grande in 2009)			6,249	5,647	5,577
EBITDA	$ 147,340	$ 123,841	$ 100,707	$ 70,195	$ 66,684

(5) Distributable cash flow is not a calculation based upon GAAP. However, the amounts included in the calculation are derived from amounts separately presented in our consolidated financial statements, with the exception 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.

Set forth below is our calculation of distributable cash flow.

	Years Ended December 31,				
	2011	2010	2009	2008	2007
			(In thousands)		
Income from continuing operations	$ 77,997	$ 58,869	$ 46,234	$ 20,696	$ 35,152
Add (subtract):					
Depreciation and amortization	33,150	30,682	26,714	21,937	12,920
Amortization of discount and deferred debt issuance costs	1,212	1,008	706	1,002	1,008
Increase in interest expense non-cash charges attributable to interest rate swaps and swap settlement costs	41	2,540	175	2,282	
Increase (decrease) in deferred revenue	(6,405)	2,035	(7,256)	11,958	(1,786)
Maintenance capital expenditures*	(5,415)	(4,487)	(3,595)	(3,133)	(1,863)
Unbilled crude settlement revenue	(4,588)				
Operating costs of acquired assets for period prior to acquisition	2,348				
Distributable cash flow from discontinued operations (excludes gain on sale of Rio Grande in 2009)			6,183	5,623	5,581
SLC Pipeline acquisition costs**			2,500		
Other non-cash adjustments	1,955	407	552		
Distributable cash flow	$ 100,295	$ 91,054	$ 72,213	$ 60,365	$ 51,012

* 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 $200 million, $159 million, $206 million and $171 million in credit agreement advances that were classified as long-term debt at December 31, 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 $295 million would have been recorded in our financial statements as increases to our properties and equipment and intangible assets instead of decreases to partners equity.

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

This Item 7, including but not limited to the sections on Liquidity and Capital Resources , contains forward-looking statements. See Forward-Looking Statements at the beginning of Part I. 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

Holly Energy Partners, L.P. is a Delaware limited partnership. 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 s Big Spring refinery in Big Spring, Texas. HFC currently owns a 42% interest in us, including the 2% general partner interest. Additionally, we own 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.

Legacy Frontier Tankage and Terminal 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 3,807,615 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 $47 million.

Agreements with HFC and Alon

We serve HFC s refineries under long-term pipeline and terminal, tankage and throughput agreements expiring in 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, 2011, these agreements with HFC will result in minimum annualized payments to us of $192 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. Also, 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, 2011, these agreements with Alon will result in minimum annualized payments to us of $30 million.

A significant reduction in revenues under these agreements would 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 pipeline and terminal personnel 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

The following tables present income, distributable cash flow and volume information for the years ended December 31, 2011, 2010 and 2009.

	Years Ended December 31, 2011[1]	Years Ended December 31, 2010	Change from 2010
	(In thousands, except per unit data)		
Revenues			
Pipelines:			
Affiliates refined product pipelines	$ 47,969	$ 48,482	$ (513)
Affiliates intermediate pipelines	21,948	20,998	950
Affiliates crude pipelines	46,480	38,932	7,548
	116,397	108,412	7,985
Third parties refined product pipelines	38,214	27,954	10,260
	154,611	136,366	18,245
Terminals, tanks and loading racks:			
Affiliates	51,229	37,964	13,265
Third parties	7,709	7,767	(58)
	58,938	45,731	13,207
Total revenues	213,549	182,097	31,452
Operating costs and expenses			
Operations	62,202	52,947	9,255
Depreciation and amortization	33,150	30,682	2,468
General and administrative	6,576	7,719	(1,143)
	101,928	91,348	10,580
Operating income	111,621	90,749	20,872
Equity in earnings of SLC Pipeline	2,552	2,393	159
Interest income		7	(7)
Interest expense, including amortization	(35,959)	(34,001)	(1,958)
Other	17	17	
	(33,390)	(31,584)	(1,806)
Income before income taxes	78,231	59,165	19,066
State income tax	(234)	(296)	62
Net income	77,997	58,869	19,128
Less general partner interest in net income, including incentive distributions[3]	16,769	12,152	4,617
Limited partners interest in net income	$ 61,228	$ 46,717	$ 14,511
Limited partners per unit interest in earnings basic and diluted[3]:	$ 2.68	$ 2.12	$ 0.56

Weighted average limited partners units outstanding	22,836	22,079	757
EBITDA[4]	$ 147,340	$ 123,841	$ 23,499
Distributable cash flow[5]	$ 100,295	$ 91,054	$ 9,241
Volumes from continuing operations (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

	Years Ended December 31, 2010	2009	Change from 2009
	(In thousands, except per unit data)		
Revenues			
Pipelines:			
Affiliates refined product pipelines	$ 48,482	$ 43,206	$ 5,276
Affiliates intermediate pipelines	20,998	16,362	4,636
Affiliates crude pipelines	38,932	29,266	9,666
	108,412	88,834	19,578
Third parties refined product pipelines	27,954	37,930	(9,976)
	136,366	126,764	9,602
Terminals, tanks and loading racks:			
Affiliates	37,964	12,561	25,403
Third parties	7,767	7,236	531
	45,731	19,797	25,934
Total revenues	182,097	146,561	35,536
Operating costs and expenses			
Operations	52,947	44,003	8,944
Depreciation and amortization	30,682	26,714	3,968
General and administrative	7,719	7,586	133
	91,348	78,303	13,045
Operating income	90,749	68,258	22,491
Equity in earnings of SLC Pipeline	2,393	1,919	474
SLC Pipeline acquisition costs		(2,500)	2,500
Interest income	7	11	(4)
Interest expense, including amortization	(34,001)	(21,501)	(12,500)
Other	17	67	(50)
	(31,584)	(22,004)	(9,580)
Income from continuing operations before income taxes	59,165	46,254	12,911
State income tax	(296)	(20)	(276)
Income from continuing operations	58,869	46,234	12,635
Discontinued operations(2)			
Income from discontinued operations, net of noncontrolling interest of $1,579		5,301	(5,301)
Gain on sale of interest in Rio Grande		14,479	(14,479)
Income from discontinued operations		19,780	(19,780)
Net income	58,869	66,014	(7,145)
Less general partner interest in net income, including incentive distributions(3)	12,152	7,947	4,205
Limited partners interest in net income	$ 46,717	$ 58,067	$ (11,350)

Limited partners earnings per unit basic and diluted[3]			
Income from continuing operations	$ 2.12	$ 2.12	$
Income from discontinued operations		0.28	(0.28)
Gain on sale of discontinued operations		0.78	(0.78)
Net income	$ 2.12	$ 3.18	$ (1.06)
Weighted average limited partners units outstanding	22,079	18,268	3,811
EBITDA[4]	$ 123,841	$ 100,707	$ 23,134
Distributable cash flow[5]	$ 91,054	$ 72,213	$ 18,841
Volumes from continuing operations (bpd)[2]			
Pipelines:			
Affiliates refined product pipelines	96,094	88,001	8,093
Affiliates intermediate pipelines	84,277	69,794	14,483
Affiliates crude pipelines	144,011	137,244	6,767
	324,382	295,039	29,343
Third parties refined product pipelines	38,910	43,709	(4,799)
	363,292	338,748	24,544
Terminals and loading racks:			
Affiliates	178,903	114,431	64,472
Third parties	39,568	42,206	(2,638)
	218,471	156,637	61,834
Total for pipelines and terminal assets (bpd)	581,763	495,385	86,378

(1) We are a consolidated variable interest entity and under common control of HFC. With respect to the November 2011 tankage and terminal acquisition from HFC, GAAP requires that our financial statements reflect the historical operations of the assets recognized by HFC, effectively as if the assets were already under our ownership and control beginning July 1, 2011 (HFC s effective date of acquisition). Accordingly, we recognized an additional $2.3 million in operating costs and $1.4 million in depreciation expense for the year ended December 31, 2011 that relate to the operation of the assets for the period from July 1, 2011 through November 8, 2011, prior to our November 9, 2011 acquisition date. There are no revenues associated with these pre-acquisition expenses. Additionally, terminal and loading rack volume information does not reflect volumes prior to our acquisition date.

(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. Pipeline volume information excludes volumes attributable to Rio Grande.

(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) 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.

(5) Distributable cash flow is not a calculation based upon GAAP. However, the amounts included in the calculation are derived from amounts separately presented in our consolidated financial statements, with the exception of equity in excess cash flows over earnings of SLC Pipeline, 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, 2011 Compared with Year Ended December 31, 2010

Summary

Net income for the year ended December 31, 2011 was $78 million, a $19.1 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 acquisitions and an increase in previously deferred revenue realized. 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 partially offset by an overall increase in operating costs and expenses.

Revenues for the year ended December 31, 2011 included the recognition of $12.4 million of prior shortfalls billed to shippers in 2011. Deficiency payments of $4 million associated with certain guaranteed shipping contracts were deferred during the year ended December 31, 2011. Such deferred revenue will be recognized in earnings either as payment for shipments in excess of guaranteed levels, or when shipping rights expire unused.

Revenues

Total revenues for the year ended December 31, 2011 were $213.5 million, a $31.5 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, the effect of annual tariff increases and the HFC crude pipeline revenue settlement. Overall pipeline shipments were up 10% from the year ended December 31, 2010.

Certain related-party pipeline volumes were down during the current year 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 $86.2 million, an increase of $9.7 million compared to the year ended December 31, 2010. This is due to a $4.3 million increase in previously deferred revenue realized and an increase in third-party refined product pipeline shipments. Volumes shipped on our refined product pipelines averaged 143.1 thousand barrels per day (mbpd) compared to 135 mbpd for 2010.

Revenues from our intermediate pipelines were $21.9 million, an increase of $1 million compared to the year ended December 31, 2010. This reflects $0.8 million in revenues attributable to the Tulsa interconnect pipelines and the effects of a $0.3 million decrease in previously deferred revenue realized. Shipments on our intermediate pipelines increased to an average of 93.4 mbpd compared to 84.3 mbpd for 2010.

Revenues from our crude pipelines were $46.5 million, an increase of $7.5 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 on our crude pipelines averaged 161.8 mbpd compared to 144 mbpd for 2010.

Revenues from terminal, tankage and loading rack fees were $58.9 million, an increase of $13.2 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 2010.

Operations Expense

Operations expense for the year ended December 31, 2011 increased by $9.3 million compared to the year ended December 31, 2010. This increase is due principally to operating costs attributable to our recently acquired assets serving HFC s El Dorado and Cheyenne refineries and an increase in maintenance services and payroll costs during the current year. With respect to our November 2011 asset acquisitions, GAAP accounting requirements required us to recognize an additional $2.3 million in operating costs that relate to the operation of the assets prior to our acquisition.

Depreciation and Amortization

Depreciation and amortization for the year ended December 31, 2011 increased by $2.5 million compared to the year ended December 31, 2010. This increase is due principally to depreciation attributable to our recent asset acquisitions from HFC and capital projects. With respect to our November 2011 asset acquisitions, GAAP accounting requirements required us to recognize an additional $1.4 million in depreciation expense that relate to the operation of the assets prior to our acquisition.

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 year ended December 31, 2011 and 2010, respectively.

Interest Expense

Interest expense for the year ended December 31, 2011 totaled $36 million, an increase of $2 million compared to year ended December 31, 2010. This increase reflects interest on increased debt levels during the current year, 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.

Results of Operations Year Ended December 31, 2010 Compared with Year Ended December 31, 2009

Summary

Income from continuing operations for the year ended December 31, 2010 was $58.9 million, a $12.6 million increase compared to the year ended December 31, 2009. This increase in overall earnings was due principally to earnings attributable to our 2009 and March 2010 asset acquisitions and overall increased shipments on our pipeline systems. These factors were partially offset by a decrease in previously deferred revenue realized and increased operating costs and expenses and interest expense.

Revenues for the year ended December 31, 2010 include the recognition of $8.4 million of prior shortfalls billed to shippers in 2009 as they did not meet their minimum volume commitments in any of the subsequent four quarters. Deficiency payments of $10.4 million associated with certain guaranteed shipping contracts were deferred during the year ended December 31, 2010.

Revenues

Total revenues from continuing operations for the year ended December 31, 2010 were $182.1 million, a $35.5 million increase compared to the year ended December 31, 2009. This increase was due principally to revenues attributable to our 2010 asset acquisitions and higher tariffs on affiliate shipments, partially offset by a $7.3 million decrease in previously deferred revenue realized. For 2010, overall pipeline shipments were up 7%, reflecting increased affiliate volumes attributable to HFC s first quarter of 2009 Navajo refinery expansion, including volumes shipped on our new 16-inch intermediate and Beeson pipelines, partially offset by a decrease in third-party shipments. Additionally, prior year affiliate shipments reflect lower volumes as a result of production downtime during a major maintenance turnaround of the Navajo refinery during the first quarter of 2009. Overall terminal and loading rack volumes also were also up in 2010, increasing 39% over 2009 levels due principally to volumes transferred and stored at our Tulsa storage and rack facilities.

Revenues from our refined product pipelines were $76.4 million, a decrease of $4.7 million compared to the year ended December 31, 2009. This decrease was due principally to an $8.5 million decrease in previously realized deferred revenue that was offset partially by an overall increase in refined product pipeline shipments. Volumes shipped on our refined product pipeline system averaged 135 mbpd compared to 131.7 mbpd for the year ended December 31, 2009, reflecting an increase in affiliate shipments, partially offset by a decline in third-party shipments.

Revenues from our intermediate pipelines were $21 million, an increase of $4.6 million compared to the year ended December 31, 2009. This increase was due principally to increased shipments on our intermediate pipeline system combined with a $1.2 million increase in previously deferred revenue realized. Volumes shipped on our intermediate product pipeline system increased to an average of 84.3 mbpd compared to 69.8 mbpd for 2009.

Revenues from our crude pipelines were $38.9 million, an increase of $9.7 million compared to the year ended December 31, 2009. This increase was due principally to an $8.4 million year-over-year increase in revenues attributable to our Roadrunner Pipeline agreement. Volumes shipped on our crude pipeline system increased to an average of 144 mbpd compared to 137.2 mbpd for 2009.

Revenues from terminal, tankage and loading rack fees were $45.7 million, an increase of $25.9 million compared to the year ended December 31, 2009. This included a $24.7 million year-over-year increase in revenues attributable to volumes transferred and stored at our Tulsa storage and rack facilities. Refined products terminalled in our facilities increased to an average of 218.5 mbpd compared to 156.6 mbpd for 2009.

Operations Expense

Operations expense for the year ended December 31, 2010 increased by $8.9 million compared to the year ended December 31, 2009. This increase was due principally to costs attributable to overall higher throughput volumes, including those from our recent asset acquisitions, and higher maintenance and payroll costs.

Depreciation and Amortization

Depreciation and amortization for the year ended December 31, 2010 increased by $4 million compared to the year ended December 31, 2009. This increase was attributable to our 2009 and March 2010 asset acquisitions and capital projects. Additionally, effective January 1, 2010, we revised the estimated useful lives of our terminal assets to 16 to 25 years resulting in a $3 million reduction in depreciation expense for the year ended December 31, 2010.

General and Administrative

General and administrative costs for the year ended December 31, 2010 of $7.7 million were relatively flat compared to $7.6 million for the year ended December 31, 2009.

Equity in Earnings of SLC Pipeline

Our equity in earnings of the SLC Pipeline was $2.4 million and $1.9 million for the years ended December 31, 2010 and 2009, respectively.

SLC Pipeline Acquisition Costs

We incurred a $2.5 million finder s fee in connection with the acquisition our SLC Pipeline joint venture interest in March 2009. As a result of accounting requirements effective January 1, 2009, we were required to expense rather than capitalize these direct acquisition costs.

Interest Expense

Interest expense for the year ended December 31, 2010 totaled $34 million, an increase of $12.5 million compared to the year ended December 31, 2009. This increase was due to interest on our 8.25% senior notes and costs of $1.1 million from a partial settlement of an interest rate swap. For the years ended December 31, 2010 and 2009, fair value adjustments to our interest rate swaps resulted in $1.5 million and $0.2 million, respectively, in non-cash interest expense. Excluding the effects of these fair value adjustments, our aggregate effective interest rate was 6.8% for the year ended December 31, 2010 compared to 5.3% for 2009.

State Income Tax

We recorded state income taxes of $296,000 and $20,000 for the years ended December 31, 2010 and 2009, respectively, which are solely attributable to the Texas margin tax. State income taxes for the year ended December 31, 2009 are presented net of a $167,000 tax refund resulting from over-estimates of prior year margin taxes.

Discontinued Operations

We sold our interest in Rio Grande on December 1, 2009. Income from discontinued operations for the year ended December 31, 2009 included a gain from the sale of our 70% interest in Rio Grande of $14.5 million. Rio Grande operations generated earnings of $6.9 million for the year ended December 31, 2009, presented net of earnings attributable to noncontrolling interest holders of $1.6 million.

LIQUIDITY AND CAPITAL RESOURCES

Overview

At December 31, 2011 we had a $275 million senior secured revolving credit agreement expiring in February 2016 (the Credit Agreement). During the year ended December 31, 2011, we received advances totaling $118 million and repaid $77 million, resulting in net borrowings of

$41 million under the Credit Agreement and an outstanding balance of $200 million at December 31, 2011.

On February 3, 2012, we amended the Credit Agreement, increasing the size of the credit facility from $275 million to $375 million. The Amended Credit Agreement expires in February 2016 and is available to fund capital expenditures, investments, acquisitions, distribution payments and working capital and for general partnership purposes. It is also available to fund letters of credit up to a $50 million sub-limit and to fund distributions to unitholders up to a $30 million sub-limit.

If any particular lender under the Amended 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 Amended 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 $781 million 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 Amended Credit Agreement will provide sufficient resources to meet our working capital liquidity needs for the foreseeable future.

In February, May, August and November 2011, we paid regular quarterly cash distributions of $0.845, $0.855, $0.865 and $0.875, respectively, on all units, an aggregate amount of $91.5 million. Included in these distributions was $13.7 million paid to the general partner as incentive distributions.

Cash and cash equivalents increased by $2.9 million during the year ended December 31, 2011. The cash flows provided by operating activities of $93.1 million exceeded the combined cash flows used for investing and financing activities of $39.3 million and $50.9 million, respectively. Working capital increased by $20.1 million to $12.3 million at December 31, 2011 from a deficit of $7.8 million at December 31, 2010.

Cash Flows - Operating Activities

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

Cash flows from operating activities decreased by $10.1 million from $103.2 million for the year ended December 31, 2010 to $93.1 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.

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 $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.

Year Ended December 31, 2010 Compared with Year Ended December 31, 2009

Cash flows from operating activities increased by $35 million from $68.2 million for the year ended December 31, 2009 to $103.2 million for the year ended December 31, 2010. This increase is due principally to $38 million in additional cash collections from our major customers, resulting from increased revenues, partially offset by year-over-year changes in payments attributable to costs of increased operations and interest.

For the year ended December 31, 2010, we received cash payments of $11.7 million under minimum volume shipping commitments. We billed $8.4 million during the year ended December 31, 2009 related to shortfalls that subsequently expired without recapture and were recognized as revenue during the year ended December 31, 2010. Another $1.4 million was included in our accounts receivable at December 31, 2010 related to shortfalls that occurred in the fourth quarter of 2010.

Cash Flows - Investing Activities

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

Cash flows used for investing activities decreased by $21.3 million from $60.6 million for the year ended December 31, 2010 to $39.3 million for the year ended December 31, 2011. During the year ended December 31, 2011, we invested $39.3 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 $25.1 million in additions to properties and equipment.

Year Ended December 31, 2010 Compared with Year Ended December 31, 2009

Cash flows used for investing activities decreased by $86.8 million from $147.4 million for the year ended December 31, 2009 to $60.6 million for the year ended December 31, 2010. During the year ended December 31, 2010, we acquired storage assets from HFC for $35.5 million and invested $25.1 million in additions to properties and equipment. During the year ended December 31, 2009, we paid $95.1 million in cash with respect to our asset acquisitions from HFC, $25.7 million for our purchase of logistics and storage assets from Sinclair, $25.5 million for our SLC Pipeline joint venture interest and $33 million in additions to properties and equipment. On December 1, 2009, we sold our 70% interest in Rio Grande for $35 million. Proceeds received are presented net of Rio Grande s cash balance of $3.1 million.

Cash Flows - Financing Activities

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

Cash flows used for financing activities were $50.9 million for the year ended December 31, 2011, an increase of $6.3 million compared to $44.6 million for the year ended December 31, 2010. During the year ended December 31, 2011, we received $118 million and repaid $77 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, 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 million and repaid $113 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. For the year ended December 31, 2010, we paid $84.4 million in regular quarterly cash distributions to our general and limited 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.

Year Ended December 31, 2010 Compared with Year Ended December 31, 2009

Cash flows used for financing activities were $44.6 million for the year ended December 31, 2010, a decrease of $121 million compared to cash flows provided by financing activities of $76.4 million for the year ended December 31, 2009. During the year ended December 31, 2010, we received $66 million and repaid $113 million in advances under the Credit Agreement. Also, 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. During the year ended December 31, 2010, we paid $84.4 million in regular quarterly cash distributions to our general and limited 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 restricted unit incentive grants. During the year ended December 31, 2009, we received $239 million and repaid $233 million in advances under the Credit Agreement. Also, we received $133.3 million in proceeds and incurred $0.3 million in costs with respect to our November and May 2009 equity offerings. During the year ended December 31, 2009, we paid $61.2 million in regular quarterly cash distributions to our general and limited partners, paid $3.1 million in excess of HFC s transferred basis in the assets acquired from HFC in 2009 and paid $1.5 million in distributions to noncontrolling interest holders in Rio Grande. Additionally during 2009, we received $3.8 million in capital contributions from our general partner and paid $0.6 million for the purchase of common units for recipients of our incentive grants.

Capital Requirements

Our pipeline and terminalling operations are capital intensive, requiring investments to maintain, expand, upgrade or enhance existing operations and to meet environmental and operational regulations. Our capital requirements consist of maintenance capital expenditures and expansion capital expenditures. 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, special 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 2012 capital budget is comprised of $8.9 million for maintenance capital expenditures and $25.8 million for expansion capital expenditures.

We recently have made certain modifications to our crude oil gathering and trunk line system that have effectively increased our ability to gather and transport an additional 10,000 bpd of Delaware Basin crude oil in response to increased drilling activity in southeast New Mexico. Furthermore, we have developed a project to replace a 5-mile section of this pipeline system that will allow for an additional 15,000 bpd of capacity that will be executed as needed if Delaware Basin crude volumes continue to increase. This project is estimated to cost approximately $2 million. We have a second project that consists of the reactivation and conversion to crude oil service of a 70-mile, 8-inch petroleum products pipeline owned by us. Once in service, this pipeline will initially be capable of transporting up to 35,000 bpd of crude oil from southeast New Mexico to third-party common carrier pipelines in west Texas for further transport to major crude oil markets. The scope of this project is being finalized. Subject to receipt of acceptable shipper support and board approval, this project could be operational in early 2013.

We are in discussions with HFC regarding our option to purchase its 75% equity interest in the UNEV Pipeline, a joint venture pipeline that is capable of transporting refined petroleum products from Salt Lake City, Utah to Las Vegas, Nevada. The initial capacity of this pipeline is 62,000 bpd, with the capacity for further expansion to 120,000 bpd. The total construction cost of this pipeline, including terminals and ethanol blending and storage facilities, was approximately $410 million. HFC s share of the cost is $308 million. The pipeline was mechanically complete in November 2011, and initial start-up activities commenced in December 2011. We are not obligated to purchase the UNEV Pipeline nor are we subject to any fees or penalties if HLS board of directors decides not to proceed with this opportunity.

We expect that our currently planned sustaining and maintenance capital expenditures as well as expenditures for acquisitions and capital development projects such as our option to purchase HFC s interest in the UNEV Pipeline described above, 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 Amended 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 Amended Credit Agreement, our ability to fund some of these capital projects may be limited, especially the UNEV Pipeline.

Credit Agreement

Our $375 million Amended Credit Agreement is available to fund capital expenditures, investments, acquisitions, distribution payments and working capital and for general partnership purposes. It is also available to fund letters of credit up to a $50 million sub-limit and to fund distributions to unitholders up to a $30 million sub-limit. The Amended Credit Agreement expires in February 2016; however, in the event that our 6.25% senior notes are not repurchased, defeased, financed, extended or repaid prior to September 1, 2014, the Amended Credit Agreement shall expire on that date.

Our obligations under the Amended Credit Agreement are collateralized by substantially all of our assets. Indebtedness under the Amended Credit Agreement is recourse to 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 Amended 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 1.00% to 2.00%) or (b) at a rate equal to the London Interbank Offered Rate (LIBOR) plus an applicable margin (ranging from 2.00% to 3.00%). In each case, the applicable margin is based upon the ratio of our funded debt (as defined in the Amended Credit Agreement) to EBITDA (earnings before interest, taxes, depreciation and amortization, as defined in the Amended Credit Agreement). We incur a commitment fee on the unused portion of the Amended Credit Agreement at an annual rate ranging from 0.375% to 0.50% based upon the ratio of our funded debt to EBITDA for the four most recently completed fiscal quarters.

The Amended Credit Agreement imposes certain requirements on us 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 agreement, the lenders will be able to accelerate the maturity of the debt and exercise other rights and remedies.

Senior Notes

Our 6.25% and 8.25% senior notes (collectively, the Senior Notes) are unsecured and impose certain restrictive covenants which we are subject to and 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 certain tankage, loading rack and crude receiving assets located at HFC s El Dorado and Cheyenne refineries. The Promissory Notes are due in full including all accrued and unpaid interest on November 1, 2016.

Indebtedness under the Promissory Notes bears interest at a rate equal to one-month LIBOR plus an applicable rate, currently 3.50%. To the extent any principal amount of the Promissory Notes is due and outstanding, the applicable rate shall increase by 0.25% on November 1, 2013 and on each February 1, May 1, August 1 and November 1 thereafter until the Promissory Notes have been paid in full. Interest is due and payable semi-annually on May 1 and November 1 of each year. However in the event that such payment is not permitted pursuant to the terms of the Amended Credit Agreement, such payment shall be deferred, and interest accrued shall be added to the principal balance outstanding of the Promissory Notes.

Subject to the Amended Credit Agreement, we may prepay the Promissory Notes in whole or in part at any time prior to the maturity date without penalty or premium. In December 2011, we repaid $77.1 million of outstanding principal using proceeds received in our December 2011 common unit offering and existing cash. At December 31, 2011, the Promissory Notes had an outstanding principal balance of $72.9 million.

Long-term Debt

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

	December 31, 2011	December 31, 2010
	(In thousands)	
Credit Agreement	$ 200,000	$ 159,000
6.25% Senior Notes		
Principal	185,000	185,000
Unamortized discount	(1,203)	(1,584)
Unamortized premium dedesignated fair value hedge	1,098	1,444
	184,895	184,860
8.25% Senior Notes		
Principal	150,000	150,000
Unamortized discount	(1,907)	(2,212)
	148,093	147,788
Promissory Notes	72,900	
Total long-term debt	$ 605,888	$ 491,648

See Risk Management for a discussion of our interest rate swap.

Long-term Contractual Obligations

The following table presents our long-term contractual obligations as of December 31, 2011.

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	Over 5 Years
	(In thousands)				
Long-term debt principal	$ 607,900	$	$ 200,000	$ 257,900	$ 150,000
Long-term debt - interest	154,588	32,298	65,203	38,524	18,563
Pipeline operating lease	35,401	6,437	12,873	12,873	3,218
Right-of-way leases	1,553	231	401	344	577
Other	15,303	1,381	2,692	2,364	8,866
Total	$ 814,745	$ 40,347	$ 281,169	$ 312,005	$ 181,224

Long-term debt consists of outstanding principal under the Credit Agreement, Senior Notes and Promissory Notes.

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, 2011. For the foreseeable future, we intend to continue renewing these agreements and expect to incur right-of-way expenses in addition to the payments listed.

Other contractual obligations consist of site service agreements with HFC expiring in 2024 through 2026, for the provision of certain 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, 2011, 2010 and 2009. Historically, the PPI has increased an average of 3.6% 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 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 with HFC, HFC has agreed to indemnify us, subject to certain limitations, for environmental noncompliance and remediation liabilities associated with assets transferred to us from HFC and occurring or existing prior to the date of such transfers. The Omnibus Agreement provides environmental indemnification with respect to certain transferred assets of up to $15 million through 2021, plus additional indemnification of $2.5 million through 2015 and up to $7.5 million through 2023. HFC s indemnification obligations under the Omnibus Agreement do not apply to (i) the Tulsa west loading racks acquired in August 2009, (ii) the 16-inch intermediate pipeline acquired in June 2009, (iii) the Roadrunner Pipeline, (iv) the Beeson Pipeline, (v) the logistics and storage assets acquired from Sinclair in December 2009, or (vi) the Tulsa east storage tanks and loading racks acquired in March 2010. For the Tulsa loading racks acquired from HFC in August 2009 and the Tulsa logistics and storage assets acquired from Sinclair in December 2009, HFC agreed to indemnify us for environmental liabilities arising from our pre-ownership operations of these assets. Additionally, HFC agreed to indemnify us for any liabilities arising from its operation of our loading racks located at HFC s Tulsa refinery west facility.

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 through 2015, subject to a $100,000 deductible and a $20 million maximum liability cap.

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, 2011, we have an accrual of $1 million that relates to environmental clean-up projects for which we have assumed liability. The remaining projects, including assessment and monitoring activities, are covered under the HFC environmental indemnification discussed above and represent liabilities of HFC.

CRITICAL ACCOUNTING POLICIES

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

Revenue Recognition

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

Billings to customers for 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 receives the future services provided by these billings,
- the period in which the customer is contractually allowed to receive the services expires, or
- we determine a high likelihood 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 or the customer acknowledges that its anticipated shipment levels will not permit it to utilize such a shortfall credit within the respective contractual make-up period. To date, we have not recognized any shortfall billings as revenue prior to the expiration of the contractual term 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 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, 2011.

Contingencies

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

New Accounting Pronouncements

Presentation of Comprehensive Income

In June 2011, an accounting standard update was issued that requires the presentation of net income and other comprehensive income in one continuous statement or in two separate, but consecutive, statements and eliminates the option to present the components of other comprehensive income in the statement of partners equity. This standard is effective January 1, 2012 and will be applied retrospectively upon implementation. This standard will not have an impact on our financial condition, results of operations and cash flows.

Intangibles Goodwill and Other: Testing Goodwill for Impairment

In September 2011, an accounting standard update was issued that allows entities an option to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. This standard is effective for annual and interim goodwill impairment tests performed beginning January 1, 2012. This standard will not have an impact on our financial condition, results of operations and cash flows.

RISK MANAGEMENT

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

As of December 31, 2011, we have an interest rate swap, designated as a cash flow hedge, that hedges our exposure to the cash flow risk caused by the effects of LIBOR changes on a $155 million Credit Agreement advance. This interest rate swap effectively converts $155 million of our LIBOR based debt to fixed rate debt having an interest rate of 0.99% plus an applicable margin, currently 2.50%, which equaled an effective interest rate of 3.49% as of December 31, 2011. This swap contract matures in February 2016.

We review publicly available information on our counterparty in order to review and monitor its financial stability and assess its ongoing ability to honor its commitments under the interest rate swap contract. This counterparty is a large financial institution. Furthermore, we have not experienced, nor do we expect to experience, any difficulty in the counterparty honoring its 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, 2011, we had an outstanding principal balance on our 6.25% and 8.25% senior notes of $185 million and $150 million, respectively. A change in interest rates would generally affect the fair value of the Senior Notes, but not our earnings or cash flows. At December 31, 2011, the fair value of our 6.25% and 8.25% senior notes were $186.9 million and $157.5 million, respectively. We estimate a hypothetical 10% change in the yield-to-maturity applicable to the 6.25% and 8.25% senior notes at December 31, 2011 would result in a change of approximately $3.1 million and $5.5 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, 2011, borrowings outstanding under the Credit Agreement were $200 million. By means of our cash flow hedge, we have effectively converted the variable rate on $155 million of outstanding borrowings to a fixed rate of 3.49%. For the remaining unhedged Credit Agreement borrowings of $45 million, a hypothetical 10% change in interest rates applicable to the Credit Agreement would not materially affect our cash flows.

At December 31, 2011, our cash and cash equivalents included highly liquid investments with a maturity of three months or less at the time of purchase. Due to the short-term nature of our cash and cash equivalents, a hypothetical 10% increase in interest rates would not have a material effect on the fair market value of our portfolio. Since we have the ability to liquidate this portfolio, we do not expect our operating results or cash flows to be materially affected by the effect of a sudden change in market interest rates on our investment portfolio.

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 cash and cash equivalents and 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 market risks associated with commodity prices.

Item 8. Financial Statements and Supplementary Data

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

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

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

Management assessed the Partnership s internal control over financial reporting as of December 31, 2011 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 concludes that, as of December 31, 2011, 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, 2011. That report appears on page 61.

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 2011, 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, 2011, 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, 2011 and 2010, and the related consolidated statements of income, cash flows, and partners equity for each of the three years in the period ended December 31, 2011, and our report dated February 24, 2012, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas

February 24, 2012

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, 2011 and 2010, and the related consolidated statements of income, cash flows, and partners equity for each of the three years in the period ended December 31, 2011. 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, 2011 and 2010, and the consolidated results of its operations and its cash flows, for each of the three years in the period ended December 31, 2011, 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, 2011, 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 24, 2012 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas

February 24, 2012

Holly Energy Partners, L.P.

Consolidated Balance Sheets

	December 31, 2011	December 31, 2010
	(In thousands, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3,269	$ 403
Accounts receivable:		
Trade	3,055	3,544
Affiliates	31,016	18,964
	34,071	22,508
Prepaid and other current assets	2,644	775
Total current assets	39,984	23,686
Properties and equipment, net	536,425	434,950
Transportation agreements, net	101,543	108,489
Goodwill	256,498	49,109
Investment in SLC Pipeline	25,302	25,437
Other assets	7,204	1,602
Total assets	$ 966,956	$ 643,273
LIABILITIES AND PARTNERS EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 6,107	$ 6,347
Affiliates	5,299	3,891
	11,406	10,238
Accrued interest	8,280	7,517
Deferred revenue	4,032	10,437
Accrued property taxes	2,196	1,990
Other current liabilities	1,777	1,262
Total current liabilities	27,691	31,444
Long-term debt	605,888	491,648
Other long-term liabilities	4,000	10,809
Partners Equity:		
Common unitholders (27,361,124 and 22,078,509 units issued and outstanding at December 31, 2011 and 2010, respectively)	482,509	271,649
General partner interest (2% interest)	(146,668)	(152,251)
Accumulated other comprehensive loss	(6,464)	(10,026)
Total partners equity	329,377	109,372
Total liabilities and partners equity	$ 966,956	$ 643,273

See accompanying notes.

Holly Energy Partners, L.P.

Consolidated Statements of Income

	Years Ended December 31, 2011	2010	2009
	(In thousands, except per unit data)		
Revenues:			
Affiliates	$ 167,626	$ 146,376	$ 101,395
Third parties	45,923	35,721	45,166
	213,549	182,097	146,561
Operating costs and expenses:			
Operations	62,202	52,947	44,003
Depreciation and amortization	33,150	30,682	26,714
General and administrative	6,576	7,719	7,586
	101,928	91,348	78,303
Operating income	111,621	90,749	68,258
Other income (expense):			
Equity in earnings of SLC Pipeline	2,552	2,393	1,919
SLC Pipeline acquisition costs			(2,500)
Interest income		7	11
Interest expense	(35,959)	(34,001)	(21,501)
Other income	17	17	67
	(33,390)	(31,584)	(22,004)
Income from continuing operations before income taxes	78,231	59,165	46,254
State income tax	(234)	(296)	(20)
Income from continuing operations	77,997	58,869	46,234
Discontinued operations			
Income from discontinued operations, net of noncontrolling interest of $1,579			5,301
Gain on sale of interest in Rio Grande Pipeline Company			14,479
Income from discontinued operations			19,780
Net income	77,997	58,869	66,014
Less general partner interest in net income, including incentive distributions	16,769	12,152	7,947
Limited partners interest in net income	$ 61,228	$ 46,717	$ 58,067
Limited partners per unit interest in earnings basic and diluted:			
Income from continuing operations	$ 2.68	$ 2.12	$ 2.12
Income from discontinued operations			0.28
Gain on sale of discontinued operations			0.78

Net income	$ 2.68	$ 2.12	$ 3.18
Weighted average limited partners units outstanding	22,836	22,079	18,268

See accompanying notes.

Holly Energy Partners, L.P.

Consolidated Statements of Cash Flows

	Years Ended December 31, 2011	2010	2009
		(In thousands)	
Cash flows from operating activities			
Net Income	$ 77,997	$ 58,869	$ 66,014
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	33,150	30,682	27,597
Equity in earnings of SLC Pipeline, net of distributions	135	482	(419)
Change in fair value interest rate swaps		1,464	175
Noncontrolling interest in earnings of Rio Grande Pipeline Company			1,579
Amortization of restricted and performance units	2,046	2,214	699
Gain on sale of interest in Rio Grande Pipeline Company			(14,479)
Operating costs of acquired assets for period prior to acquisition	2,348		
(Increase) decrease in current assets:			
Accounts receivable trade	489	1,149	388
Accounts receivable affiliates	(12,051)	(4,890)	(4,679)
Prepaid and other current assets	(1,406)	(36)	(146)
Current assets of discontinued operations		2,195	
Increase (decrease) in current liabilities:			
Accounts payable trade	(767)	2,487	(1,956)
Accounts payable affiliates	1,409	1,540	149
Accrued interest	763	4,654	18
Deferred revenue	(6,405)	2,035	(7,256)
Accrued property taxes	206	918	(74)
Other current liabilities	515	5	(248)
Other, net	(5,310)	(600)	833
Net cash provided by operating activities	93,119	103,168	68,195
Cash flows from investing activities			
Additions to properties and equipment	(39,337)	(25,103)	(32,999)
Acquisition of tankage and terminal assets from HollyFrontier Corporation		(35,526)	(95,080)
Acquisition of logistics assets from Sinclair Oil Company			(25,665)
Investment in SLC Pipeline			(25,500)
Proceeds from sale of interest in Rio Grande Pipeline Company, net of transferred cash			31,865
Net cash used for investing activities	(39,337)	(60,629)	(147,379)
Cash flows from financing activities			
Borrowings under credit agreement	118,000	66,000	239,000
Repayments of credit agreement borrowings	(77,000)	(113,000)	(233,000)
Repayments of promissory notes	(77,100)		
Proceeds from issuance of senior notes		147,540	
Proceeds from issuance of common units	75,815		133,301
Capital contribution from general partner	5,887		3,812
Distributions to unitholders	(91,506)	(84,426)	(61,188)
Distributions to noncontrolling interest			(1,500)
Purchase price in excess of transferred basis in assets acquired from HollyFrontier Corporation		(57,560)	(3,120)
Purchase of units for incentive grants	(1,641)	(2,704)	(616)
Deferred financing costs	(3,150)	(494)	
Other	(221)		(266)
Net cash provided by (used for) financing activities	(50,916)	(44,644)	76,423

Cash and cash equivalents						
Increase (decrease) for the year		2,866		(2,105)		(2,761)
Beginning of year		403		2,508		5,269
End of year	$	3,269	$	403	$	2,508

See accompanying notes.

Holly Energy Partners, L.P.

Consolidated Statements of Partners Equity

	Holly Energy Partners, L.P. Partners Equity (Deficit):						
	Common Units	Subordinated Units	Class B Subordinated Units	General Partner Interest	Accumulated Other Comprehensive Loss	Non-controlling Interest	Total
				(In thousands)			
Balance December 31, 2008	$ 169,126	$ (85,059)	$ 21,455	$ (94,653)	$ (12,967)	$ 10,218	$ 8,120
Issuance of common units	186,801						186,801
Cost of issuing common units	(266)						(266)
Conversion of subordinated units	(90,824)	90,824					
Capital contribution				3,812			3,812
Distributions to unitholders	(35,245)	(16,275)	(2,925)	(6,743)			(61,188)
Distributions to noncontrolling interest						(1,500)	(1,500)
Purchase price in excess of transferred basis in assets acquired from HollyFrontier				(3,120)			(3,120)
Purchase of units for incentive grants	(616)						(616)
Amortization of restricted and performance units	699						699
Elimination of noncontrolling Interest upon sale of Rio Grande						(10,297)	(10,297)
Comprehensive income:							
Net income	45,878	10,510	2,896	6,730		1,579	67,593
Other comprehensive income					3,826		3,826
Comprehensive income	45,878	10,510	2,896	6,730	3,826	1,579	71,419
Balance December 31, 2009	275,553		21,426	(93,974)	(9,141)		193,864
Conversion of Class B subordinated units	20,588		(20,588)				
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	46,884		681	11,304			58,869
Other comprehensive loss					(885)		(885)
Comprehensive income	46,884		681	11,304	(885)		57,984
Balance December 31, 2010	271,649			(152,251)	(10,026)		109,372
Issuance of common units	75,815						75,815
Cost of issuing common units	(308)						(308)
Capital contribution				5,887			5,887
Distributions to unitholders	(75,951)			(15,555)			(91,506)

Tankage and terminal assets acquired from HollyFrontier:							
Transferred basis in properties and goodwill	295,450						295,450
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	62,988			15,009			77,997
Other comprehensive income					3,562		3,562
Comprehensive income	62,988			15,009	3,562		81,559
Balance December 31, 2011	$ 482,509	$	$	$ (146,668)	$ (6,464)	$	$ 329,377

See accompanying notes.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2011

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

Description of Business

Holly Energy Partners, L.P. (HEP) together with its consolidated subsidiaries, is a publicly held master limited partnership, currently 42% owned (including the 2% general partner interest) by HollyFrontier Corporation (formerly known as Holly Corporation) (HFC) and its subsidiaries. HFC changed its name in connection with the consummation of its merger of equals with Frontier Oil Corporation effective July 1, 2011.

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 operating segment - the operation of petroleum product and crude pipelines and terminals, tankage and loading rack facilities.

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. Additionally, 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 directly exposed to changes in commodity prices.

Principles of Consolidation and Common Control Transactions

The consolidated financial statements include our accounts and those of our subsidiaries. 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 $295 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 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 major replacements are generally 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 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, 2011.

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, 2011, our underlying equity in the SLC Pipeline was $60.9 million compared to our recorded investment balance of $25.3 million, a difference of $35.6 million. We are amortizing this difference as an adjustment to our pro-rata share of earnings.

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, 2011 and 2010, we have retirement obligations of $0.7 million that are recorded under Other long-term liabilities in our consolidated balance sheets.

Revenue Recognition

Revenues are recognized as products are shipped through our pipelines and terminals or other services have been rendered. Billings to customers for 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 receives the future services provided by these billings,

- the period in which the customer is contractually allowed to receive the services expires, or we determine a high likelihood 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 or the customer acknowledges that its anticipated shipment levels will not permit it to utilize such a shortfall credit within the respective contractual make-up period. To date, we have not recognized any shortfall billings as revenue prior to the expiration of the contractual term 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.

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. Environmental costs recoverable through insurance, indemnification agreements or other sources are included in other assets to the extent such recoveries are considered probable. At December 31, 2011 and 2010, we had net accruals for environmental remediation obligations of $1 million and $0.3 million, respectively.

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 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 (including subordinated unit holders) is computed by dividing limited partners interest in net income, after deducting the general partner s 2% interest and incentive distributions, by the weighted-average number of outstanding common and subordinated units. We have not had any subordinated units outstanding since May 2010.

New Accounting Pronouncements

Presentation of Comprehensive Income

In June 2011, an accounting standard update was issued that requires the presentation of net income and other comprehensive income in one continuous statement or in two separate, but consecutive, statements and eliminates the option to present the components of other comprehensive income in the statement of partners equity. This standard is effective January 1, 2012 and will be applied retrospectively upon implementation. This standard will not have an impact on our financial condition, results of operations and cash flows.

Intangibles Goodwill and Other: Testing Goodwill for Impairment

In September 2011, an accounting standard update was issued that allows entities an option to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. This standard is effective for annual and interim goodwill impairment tests performed beginning January 1, 2012. This standard will not have an impact on our financial condition, results of operations and cash flows.

Note 2: Discontinued Operations

On December 1, 2009, we sold our 70% interest in Rio Grande to a subsidiary of Enterprise Products Partners LP for $35 million. Results of operations of Rio Grande and the $14.5 million gain on the sale are presented in discontinued operations.

Cash flows from discontinued operations have been combined with cash flows from continuing operations for presentation purposes in the Consolidated Statements of Cash Flows. For the year ended December 31, 2009, net cash flows from our discontinued Rio Grande operations were $37.6 million, which included $35 million in proceeds received upon the sale of our Rio Grande interest.

Note 3: Acquisitions

2011 Acquisition

Legacy Frontier Tankage and Terminal 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 3,807,615 of our common units. In connection with the transaction, we entered into 15-year throughput agreements with HFC that result in minimum annual revenue commitments to us of $47 million. This transaction meets the criteria of a business combination under GAAP. Since we are a consolidated variable interest entity of HFC, we accounted for this transaction as a business combination between entities under common control and therefore, we have recorded this transfer at HFC s cost basis. In addition, we have retrospectively adjusted our operating results as if HFC had contributed these assets to us on July 1, 2011 (date of HFC s merger with Frontier Oil Corporation). 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 million liability representing the promissory notes issued to HFC at the time of the closing of this transaction and a corresponding decrease to HFC s non-cash contribution.

For the year ended December 31, 2011, our consolidated statement of income includes revenues of $7.1 million and net income of $1.6 million that are attributable to the operations of these assets. Although these assets did not generate revenues prior to November 9, 2011, our operating results include operating costs and depreciation expense of these assets beginning July 1, 2011 of which $3.8 million was incurred by HFC prior to our acquisition date. Of this amount, $2.3 million represents actual cash operating costs incurred by HFC and not by us, which we have recorded as additional non-cash capital contribution.

Assuming this acquisition had occurred on January 1, 2010 and our throughput agreements with HFC were in effect at this time, pro forma revenues, net income and earnings per unit are estimated to have been as follows:

	Years Ended December 31, 2011	2010
	(In thousands) (Unaudited)	
Revenues	$ 253,679	$ 229,113
Net income	$ 109,087	$ 90,828
Basic and diluted earnings per unit	$ 3.46	$ 2.94

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.

In accounting for these 2010 acquisitions 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.

2009 Acquisitions

Sinclair Logistics and Storage Asset Transaction

On December 1, 2009, we acquired from an affiliate of Sinclair Oil Company (Sinclair) storage tanks having approximately 1.4 million barrels of storage capacity and loading racks at its refinery located in Tulsa, Oklahoma for $79.2 million. The purchase price consisted of $25.7 million in cash, including $4.2 million in taxes and 1,373,609 of our common units having a fair value of $53.5 million. Separately, HFC, also a party to the transaction acquired Sinclair s Tulsa refinery.

With respect to this purchase, we recorded $30.2 million in properties and equipment, $49.1 million in goodwill and $0.2 million in other long-term liabilities. The value of the acquired assets, which does not include goodwill, is based on fair value using a cost approach methodology.

Roadrunner / Beeson Pipelines Transaction

Also on December 1, 2009, we acquired from HFC two newly constructed pipelines for $46.5 million, consisting of a 65-mile, 16-inch crude oil pipeline (the Roadrunner Pipeline) that connects the Navajo refinery facility located in Lovington, New Mexico to a terminus of Centurion Pipeline L.P. s pipeline extending between west Texas and Cushing, Oklahoma and a 37-mile, 8-inch crude oil pipeline that connects our New Mexico crude oil gathering system to the Navajo refinery Lovington facility (the Beeson Pipeline).

Tulsa West Loading Racks Transaction

On August 1, 2009, we acquired from HFC for $17.5 million certain truck and rail loading/unloading facilities located at HFC s Tulsa refinery west facility. The racks load refined products and lube oils produced at the Tulsa refinery onto rail cars and/or tanker trucks.

Lovington-Artesia Pipeline Transaction

On June 1, 2009, we acquired from HFC a newly constructed 16-inch intermediate pipeline for $34.2 million. The pipeline runs 65 miles from the Navajo refinery s crude oil distillation and vacuum facilities in Lovington, New Mexico to its petroleum refinery located in Artesia, New Mexico.

In accounting for our 2009 acquisitions from HFC, consisting of the Roadrunner and Beeson Pipelines, the Tulsa west loading rack facilities and 16-inch intermediate pipeline as discussed above, we recorded total property and equipment of $95.1 million representing HFC s historical basis in the transferred assets. The $3.1 million aggregate purchase price in excess of HFC s historical basis in the assets was recorded as a decrease to our partners equity.

SLC Pipeline Joint Venture Interest

On March 1, 2009, we acquired a 25% joint venture interest in the SLC Pipeline, a new 95-mile intrastate pipeline system that we jointly own with All American Pipeline, L.P. (Plains). The total cost of our investment in the SLC Pipeline was $28 million, consisting of the capitalized $25.5 million joint venture contribution and the $2.5 million finder s fee paid to HFC that was expensed as acquisition costs.

Note 4: Financial Instruments
Fair Value Measurements

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.

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, debt and an interest rate swap. 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.

At December 31, 2011, our debt consists of borrowings outstanding under our $275 million revolving credit agreement (the Credit Agreement), our 6.25% senior notes due 2015, our 8.25% senior notes due 2018 and our promissory notes due to HFC. The $200 million carrying amount of outstanding debt under the Credit Agreement and the $72.9 million due HFC under the promissory notes approximate fair value as interest rates are reset frequently using current rates. The estimated fair values of our 6.25% and 8.25% senior notes were $186.9 million and $157.5 million, respectively, at December 31, 2011. These fair value estimates are based on values provided from a third-party bank, which were derived using market quotes for similar debt instruments (a Level 2 input). See Note 8 for additional information on these instruments.

We have an interest rate swap that is measured at fair value on a recurring basis using Level 2 inputs that, as of December 31, 2011, represented a liability having a fair value of $0.5 million. With respect to this instrument, fair value is based on the net present value of expected future cash flows related to both variable and fixed rate legs of our interest rate swap agreement. Our 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 our interest rate swap.

Note 5: Properties and Equipment

	December 31, 2011	December 31, 2010
	(In thousands)	
Pipelines, terminals and tankage	$ 633,095	$ 507,260
Land and right of way	27,149	25,264
Other	16,507	14,591
Construction in progress	14,419	16,601
	691,170	563,716
Less accumulated depreciation	154,745	128,766
	$ 536,425	$ 434,950

We capitalized $0.9 million and $0.5 million in interest related to major construction projects during the years ended December 31, 2011 and 2010, respectively.

Depreciation expense was $26.2 million, $23.7 million and $19.7 million for the years ended December 31, 2011, 2010 and 2009, respectively.

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 (at which time we were not a consolidated variable interest entity of HFC) that are based on the respective agreement s expected future earnings contribution. 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 are as follows:

	December 31, 2011	December 31, 2010
	(In thousands)	
Alon transportation agreement	$ 59,933	$ 59,933
HFC transportation agreement	74,231	74,231
	134,164	134,164
Less accumulated amortization	32,621	25,675
	$ 101,543	$ 108,489

Amortization expense was $6.9 million, $6.9 million and $7 million for the years ended December 31, 2011, 2010 and 2009, 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 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 $3.6 million, $2.9 million and $2.8 million for the years ended December 31, 2011, 2010 and 2009, respectively. These amounts include retirement costs of $2.2 million, $1.5 million and $1.6 million for the years ended December 31, 2011, 2010 and 2009, respectively.

We have an incentive plan (Long-Term Incentive Plan) for employees, consultants 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, 2011, we have two types of equity-based compensation, which are described below. The compensation cost charged against income for these plans was $2.1 million, $2.2 million and $1.2 million for the years ended December 31, 2011, 2010 and 2009, 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. At December 31, 2011, 350,000 units were authorized to be granted under the equity-based compensation plans, of which 60,604 had 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 directors who perform services for us, with vesting generally over a period of one to five 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, 2011 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, 2011 (not vested)	47,295	$ 37.47		

Granted	24,650	58.09		
Vesting and transfer of full ownership to recipients	(34,607)	39.67		
Forfeited	(7,802)	43.71		
Outstanding at December 31, 2011 (not vested)	29,536	$ 50.45	1 year	$ 1,557

The fair values of restricted units that were vested and transferred to recipients during the years ended December 31, 2011, 2010 and 2009 were $1.4 million, $1.6 million and $1.2 million, respectively. As of December 31, 2011, there was $0.5 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 year.

Performance Units

Under our Long-Term Incentive Plan, we grant performance units to selected executives who perform services for us. Performance units granted in 2011 and 2010 are payable based upon the growth in distributable cash flow per common unit over the performance period, and vest over a period of three years. Performance units granted in 2009 are payable based upon the growth in distributions on our common units during the requisite period, and vest over a period of three years. As of December 31, 2011, estimated share payouts for outstanding nonvested performance unit awards were approximately 110%.

We granted 8,969 performance units to certain officers in March 2011. These units will vest over a three-year performance period ending December 31, 2013 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 that the performance units are granted. The fair value of these performance units is based on the grant date closing unit price of $59.65 and will apply to the number of units ultimately awarded.

A summary of performance unit activity and changes during the year ended December 31, 2011 is presented below:

Performance Units	**Payable In Units**
Outstanding at January 1, 2011 (not vested)	59,415
Granted	8,969
Vesting and payment of units to recipients	(25,393)
Forfeited	
Outstanding at December 31, 2011 (not vested)	42,991

The fair value of performance units vested and transferred to recipients during the years ended December 31, 2011, 2010 and 2009 was $0.9 million, $0.6 million and $0.4 million, respectively. Based on the weighted average fair value at December 31, 2011 of $36.52, there was $0.6 million of total unrecognized compensation expense related to nonvested performance units, which is expected to be recognized over a weighted-average period of 0.7 year.

During the year ended December 31, 2011, we paid $1.6 million for the purchase of our common units in the open market for issuance and settlement of all unit awards under our Long-Term Incentive Plan.

Note 8: Debt

Credit Agreement

At December 31, 2011, the Credit Agreement consisted of a $275 million senior secured revolving credit facility expiring in February 2016. During the year ended December 31, 2011, we received advances totaling $118 million and repaid $77 million, resulting in net borrowings of $41 million under the Credit Agreement and an outstanding balance of $200 million at December 31, 2011.

On February 3, 2012, we amended the Credit Agreement, increasing the size of the credit facility from $275 million to $375 million (the Amended Credit Agreement) and is available to fund capital expenditures, investments, acquisitions, distribution payments and working capital and for general partnership purposes. It is also available to fund letters of credit up to a $50 million sub-limit and to fund distributions to unitholders up to a $30 million sub-limit. The Amended Credit Agreement expires in February 2016; however, in the event that our 6.25% senior notes are not repurchased, defeased, financed, extended or repaid prior to September 1, 2014, the Amended Credit Agreement shall expire on that date.

Our obligations under the Amended Credit Agreement are collateralized by substantially all of our assets. Indebtedness under the Amended 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 Amended 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 1.00% to 2.00%) or (b) at a rate equal to LIBOR plus an applicable margin (ranging from 2.00% to 3.00%). In each case, the applicable margin is based upon the ratio of our funded debt (as defined in the Amended Credit Agreement) to EBITDA (earnings before interest, taxes, depreciation and amortization, as defined in the Amended Credit Agreement). We incur a commitment fee on the unused portion of the Amended Credit Agreement at an annual rate ranging from 0.375% to 0.50% based upon the ratio of our funded debt to EBITDA for the four most recently completed fiscal quarters.

The Amended Credit Agreement imposes certain requirements on us which we are subject to and 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 Amended Credit Agreement, the lenders will be able to accelerate the maturity of the debt and exercise other rights and remedies.

Senior Notes

In March 2010, we issued $150 million in aggregate principal amount outstanding of 8.25% senior notes maturing March 15, 2018. A portion of the $147.5 million in net proceeds received was used to fund our $93 million purchase of the Tulsa and Lovington storage assets from HFC on March 31, 2010. Additionally, we used a portion to repay $42 million in outstanding Credit Agreement borrowings, with the remaining proceeds available for general partnership purposes, including working capital and capital expenditures.

Our 6.25% senior notes having an aggregate principal amount outstanding of $185 million mature March 1, 2015 and are registered with the SEC. The 6.25% and 8.25% senior notes (collectively, the Senior Notes) are unsecured and impose certain restrictive covenants, which we are subject to and 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 certain tankage, loading rack and crude receiving assets located at HFC s El Dorado and Cheyenne refineries (see Note 3). The Promissory Notes are due in full including all accrued and unpaid interest on November 1, 2016.

Indebtedness under the Promissory Notes bears interest at a rate equal to one-month LIBOR plus an applicable rate, currently 3.50%. To the extent any principal amount of the Promissory Notes is due and outstanding, the applicable rate shall increase by 0.25% on November 1, 2013 and on each February 1, May 1, August 1 and November 1 thereafter until the Promissory Notes have been paid in full. Interest is due and payable semi-annually on May 1 and November 1 of each year. However in the event that such payment is not permitted pursuant to the terms of the Amended Credit Agreement, such payment shall be deferred, and interest accrued shall be added to the principal balance outstanding of the Promissory Notes.

Subject to the terms of the Amended Credit Agreement, we may prepay the Promissory Notes in whole or in part at any time prior to the maturity date without penalty or premium. In December 2011, we repaid $77.1 million of outstanding principal using proceeds received in our December 2011 common unit offering and existing cash. At December 31, 2011, the Promissory Notes had an outstanding principal balance of $72.9 million.

Long-term Debt

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

	December 31, 2011	December 31, 2010
	(In thousands)	
Credit Agreement	$ 200,000	$ 159,000
6.25% Senior Notes		
Principal	185,000	185,000
Unamortized discount	(1,203)	(1,584)
Unamortized premium dedesignated fair value hedge	1,098	1,444
	184,895	184,860
8.25% Senior Notes		
Principal	150,000	150,000
Unamortized discount	(1,907)	(2,212)
	148,093	147,788
Promissory Notes	72,900	
Total long-term debt	$ 605,888	$ 491,648

Maturities of our long-term debt are as follows:

	(In thousands)
Years Ending December 31,	
2012	$
2013	
2014	200,000
2015	185,000
2016	72,900
Thereafter	150,000
Total	$ 607,900

Interest Rate Risk Management

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

As of December 31, 2011, we have an interest rate swap contract that hedges our exposure to the cash flow risk caused by the effects of LIBOR changes on a $155 million Credit Agreement advance. This interest rate swap effectively converts $155 million of our LIBOR based debt to fixed-rate debt having an interest rate of 0.99% plus an applicable margin, currently 2.50%, which equaled an effective interest rate of 3.49% as of December 31, 2011. This swap contract matures in February 2016.

We have designated this interest rate swap as a cash flow hedge. Based on our assessment of effectiveness using the change in variable cash flows method, we have determined that this interest rate swap is effective in offsetting the variability in interest payments on $155 million of our variable-rate debt resulting from changes in LIBOR. Under hedge accounting, we adjust our cash flow hedge on a quarterly basis to its fair value with the offsetting fair value adjustment 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 swap against the expected future interest payments on $155 million of our variable-rate debt. Any ineffectiveness is reclassified from accumulated other comprehensive loss to interest expense. As of December 31, 2011, we had no ineffectiveness on this cash flow hedge.

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, 2011, we had an accumulated other comprehensive loss of $6.5 million that relates to our current and previous cash flow hedging instruments. Of this amount, $6 million relates to our cash flow hedge terminated in December 2011 and represents the application of hedge accounting prior to termination. This amount will be amortized as a charge to interest expense through February 2013, the remaining term of the terminated swap contract. Of the remaining $0.5 million amount, approximately $0.1 million will be effectively transferred from accumulated other comprehensive loss to 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, 2011				
Interest rate swap designated as cash flow hedging instrument:				
Variable-to-fixed interest rate swap contract ($155 million of LIBOR based debt interest)	Other long-term liabilities	$ 520	Accumulated other comprehensive loss	$ 520
December 31, 2010				
Interest rate swap designated as cash flow hedging instrument:				
Variable-to-fixed interest rate swap contract ($155 million of LIBOR based debt interest)	Other long-term liabilities	$ 10,026	Accumulated other comprehensive loss	$ 10,026

We previously had interest rate swap contracts that served as economic hedges on interest attributable to outstanding debt. For the years ended December 31, 2010 and 2009, we recognized $1.5 million and $0.2 million, respectively, 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, is being amortized as a reduction to interest expense over the remaining term of our 6.25% senior notes.

Interest Expense and Other Debt Information

Interest expense consists of the following components:

	Years Ended December 31,		
	2011	**2010**	**2009**
		(In thousands)	
Interest on outstanding debt:			
Credit Agreement, net of interest on interest rate swap	$ 10,477	$ 9,109	$ 10,657
6.25% senior notes	11,565	11,404	10,703
8.25% senior notes	12,380	10,298	
Promissory Notes	745		

Partial settlement of interest rate swap cash flow hedge		1,076	
Net fair value adjustments to interest rate swaps (1)	41	1,464	175
Net amortization of discount and deferred debt issuance costs	1,212	713	706
Commitment fees	430	392	268
Total interest incurred	36,850	34,456	22,509
Less capitalized interest	891	455	1,008
Net interest expense	$ 35,959	$ 34,001	$ 21,501
Cash paid for interest (2)	$ 34,825	$ 31,305	$ 21,721

(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 contracts of $1.9 million and $3.8 million for the years ended December 31, 2010 and 2009, respectively.

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, 2011, the minimum future rental commitments under operating leases having non-cancelable lease terms in excess of one year are as follows:

	(In thousands)
Years Ending December 31,	
2012	$ 6,668
2013	6,665
2014	6,609
2015	6,609
2016	6,608
Thereafter	3,795
Total	$ 36,954

Rental expense charged to operations was $7.4 million, $7.1 million and $7.1 million for the years ended December 31, 2011, 2010 and 2009, 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 96% 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 from continuing operations generated by each of these customers:

	Years Ended December 31,		
	2011	**2010**	**2009**
HFC	78%	80%	69%
Alon	18%	12%	26%

Note 11: Related Party Transactions

We serve HFC s refineries under long-term pipeline and terminal, tankage and throughput agreements expiring in 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 the Federal Energy Regulatory Commission (FERC) index. As of December 31, 2011, these agreements with HFC will result in minimum annualized payments to us of $192 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.

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 pipeline and terminal personnel 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 \$167.6 million, \$146.4 million and \$101.4 million for the years ended December 31, 2011, 2010 and 2009, respectively.

HFC charged general and administrative services under the Omnibus Agreement of \$2.3 million for each of the years ended December 31, 2011, 2010 and 2009.

We reimbursed HFC for costs of employees supporting our operations of \$21.4 million, \$18.6 million and \$17 million for the years ended December 31, 2011, 2010 and 2009, respectively.

HFC reimbursed us \$11.9 million, \$3.7 million and \$1.7 million for certain costs paid on their behalf for the years ended December 31, 2011, 2010 and December 31, 2009, respectively.

We paid HFC a \$2.5 million finder s fee in connection the acquisition of our 25% joint venture interest in the SLC Pipeline in the first quarter of 2009.

We distributed \$40.6 million, \$35.9 million and \$29.5 million for the years ended December 31, 2011, 2010 and 2009, respectively, to HFC as regular distributions on its common units, subordinated units and general partner interest, including general partner incentive distributions.

Accounts receivable from HFC were \$31 million and \$19 million at December 31, 2011 and 2010, respectively.

Accounts payable to HFC were \$5.3 million and \$3.9 million at December 31, 2011 and 2010, respectively.

Revenues for the years ended December 31, 2011, 2010 and 2009 include \$3.3 million, \$3.6 million and \$2.4 million, of shortfall payments billed in 2010, 2009 and 2008, respectively, as HFC did not exceed its minimum volume commitment in any of the subsequent four quarters in 2011, 2010 and 2009. Deferred revenue in the consolidated balance sheets at December 31, 2011 and 2010 includes \$4 million and \$3.3 million, respectively, related to certain shortfall billings. It is possible that HFC may not exceed its minimum obligations to receive credit for any of the \$4 million deferred at December 31, 2011.

We acquired various pipeline, terminal and tankage assets from HFC in 2011, 2010 and 2009. See Note 3 for a description of these transactions.

Note 12: Partners Equity, Income Allocations and Cash Distributions

HFC currently holds 11,097,615 of our common units and the 2% general partner interest, which together constitutes a 42% ownership interest in us.

Common Unit Issuances

2011 Issuances

We issued in a public offering 1,475,000 of our common units priced at $53.50 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 3,807,615 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.

2009 Issuances

We issued 1,373,609 of our common units having a value of $53.5 million to Sinclair as partial consideration of our total $79.2 million purchase of Sinclair s Tulsa logistics assets in December 2009.

We issued in a public offering 2,185,000 of our common units priced at $35.78 per unit in November 2009. Aggregate net proceeds of $74.9 million were used to fund the cash portion of our December 2009 asset acquisitions, to repay outstanding borrowings under the Credit Agreement and for general partnership purposes.

Additionally, we issued in a public offering 2,192,400 of our common units priced at $27.80 per unit in May 2009. Net proceeds of $58.4 million were used to repay outstanding borrowings under the Credit Agreement and for general partnership purposes.

We received aggregate capital contributions of $3.8 million from our general partner to maintain its 2% general partner interest concurrent with the 2009 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 $781 million 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 Holly Energy Partners, L.P. 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,		
	2011	**2010**	**2009**
		(In thousands)	
General partner interest in net income	$ 1,250	$ 971	$ 1,210
General partner incentive distribution	15,519	11,181	6,737
Total general partner interest in net income attributable to HEP	$ 16,769	$ 12,152	$ 7,947

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 presented below:

	Total Quarterly Distribution Target Amount	Marginal Percentage Interest in Distributions	
		Unitholders	General Partner
Minimum quarterly distribution	$0.50	98%	2%
First target distribution	Up to $0.55	98%	2%
Second target distribution	above $0.55 up to $0.625	85%	15%
Third target distribution	above $0.625 up to $0.75	75%	25%
Thereafter	Above $0.75	50%	50%

On January 25, 2012, we announced our cash distribution for the fourth quarter of 2011 of $0.885 per unit. The distribution is payable on all common and general partner units and will be paid February 14, 2012 to all unitholders of record on February 6, 2012.

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,		
	2011	2010	2009
	(in thousands, except per unit data)		
General partner interest	$ 1,981	$ 1,724	$ 1,356
General partner incentive distribution	15,519	11,181	6,737
Total general partner distribution	17,500	12,905	8,093
Limited partner distribution	81,508	73,223	59,725
Total regular quarterly cash distribution	$ 99,008	$ 86,128	$ 67,818
Cash distribution per unit applicable to limited partners	$ 3.48	$ 3.32	$ 3.16

As a master limited partnership, we distribute our available cash, which has historically exceeded our net income 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. Additionally, if the assets contributed and acquired 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 $295 million 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: Comprehensive Income

We have other comprehensive income resulting from fair value adjustments to our cash flow hedge. Our comprehensive income is as follows:

	Years Ended December 31,		
	2011	2010	2009
	(In thousands)		
Net income	$ 77,997	$ 58,869	$ 67,593

Other comprehensive income (loss):			
Change in fair value of cash flow hedge	3,521	(1,961)	3,826
Amortization of unrealized loss attributable to discontinued cash flow hedge	41		
Reclassification adjustment to net income on partial settlement of cash flow hedge		1,076	
Other comprehensive income (loss)	3,562	(885)	3,826
Comprehensive income	81,559	57,984	71,419
Less noncontrolling interest in comprehensive income			1,579
Comprehensive income attributable to HEP unitholders	$ 81,559	$ 57,984	$ 69,840

Note 14: Quarterly Financial Data (Unaudited)

Summarized quarterly financial data is as follows:

	First	Second	Third[1]	Fourth	Total
		(In thousands, except per unit data)			
Year Ended December 31, 2011					
Revenues	$ 45,017	$ 50,940	$ 49,268	$ 68,324	$ 213,549
Operating income	$ 23,218	$ 27,288	$ 22,204	$ 38,911	$ 111,621
Income before income taxes	$ 15,397	$ 19,031	$ 14,037	$ 29,766	$ 78,231
Net income	$ 15,169	$ 19,013	$ 14,114	$ 29,701	$ 77,997
Limited partners interest in net income	$ 11,607	$ 15,166	$ 10,159	$ 24,296	$ 61,228
Limited partners per unit interest in net income basic and diluted	$ 0.53	$ 0.69	$ 0.46	$ 0.97	$ 2.68
Distributions per limited partner unit	$ 0.855	$ 0.865	$ 0.875	$ 0.885	$ 3.48
Year Ended December 31, 2010					
Revenues	$ 40,696	$ 45,483	$ 46,549	$ 49,369	$ 182,097
Operating income	$ 17,863	$ 22,484	$ 24,172	$ 26,230	$ 90,749
Income before income taxes	$ 10,796	$ 13,481	$ 16,335	$ 18,553	$ 59,165
Net income	$ 10,702	$ 13,435	$ 16,259	$ 18,473	$ 58,869
Limited partners interest in net income	$ 8,056	$ 10,526	$ 13,087	$ 15,048	$ 46,717
Limited partners per unit interest in net income basic and diluted	$ 0.36	$ 0.48	$ 0.59	$ 0.68	$ 2.12
Distributions per limited partner unit	$ 0.815	$ 0.825	$ 0.835	$ 0.845	$ 3.32

(1) As a result of our November 9, 2011 tankage and terminal asset acquisition from HFC (see Note 3), we have retrospectively adjusted our third quarter of 2011 operating costs and expenses to include expenses incurred by HFC prior to our acquisition. Therefore, summarized quarterly financial data for the third quarter of the year ended December 31, 2011 does not agree to amounts previously reported.

Note 15: Supplemental Guarantor / Non-Guarantor Financial Information

Obligations of Holly Energy Partners, L.P. (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.

We sold our 70% interest in Rio Grande on December 1, 2009; therefore, Rio Grande is no longer a subsidiary of HEP. Rio Grande (Non-Guarantor) was the only subsidiary that did not guarantee these obligations. Amounts attributable to Rio Grande prior to our sale are presented in discontinued operations.

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

Condensed Consolidating Balance Sheet

December 31, 2011	Parent	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
ASSETS				
Current assets:				
Cash and cash equivalents	$ 2	$ 3,267	$	$ 3,269
Accounts receivable		34,071		34,071
Intercompany accounts receivable (payable)	17,745	(17,745)		
Prepaid and other current assets	266	2,378		2,644
Total current assets	18,013	21,971		39,984
Properties and equipment, net		536,425		536,425
Investment in subsidiaries	651,217		(651,217)	
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	$ 670,552	$ 947,621	$ (651,217)	$ 966,956
LIABILITIES AND PARTNERS EQUITY				
Current liabilities:				
Accounts payable	$	$ 11,406	$	$ 11,406
Accrued interest	7,498	782		8,280
Deferred revenue		4,032		4,032
Accrued property taxes		2,196		2,196
Other current liabilities	689	1,088		1,777
Total current liabilities	8,187	19,504		27,691
Long-term debt	332,988	272,900		605,888
Other long-term liabilities		4,000		4,000
Partners equity	329,377	651,217	(651,217)	329,377
Total liabilities and partners equity	$ 670,552	$ 947,621	$ (651,217)	$ 966,956

Condensed Consolidating Balance Sheet

December 31, 2010	Parent	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
ASSETS				
Current assets:				
Cash and cash equivalents	$ 2	$ 401	$	$ 403

Accounts receivable		22,508		22,508
Intercompany accounts receivable (payable)	(92,230)	92,230		
Prepaid and other current assets	235	540		775
Total current assets	(91,993)	115,679		23,686
Properties and equipment, net		434,950		434,950
Investment in subsidiaries	541,262		(541,262)	
Transportation agreements, net		108,489		108,489
Goodwill		49,109		49,109
Investment in SLC Pipeline		25,437		25,437
Other assets	1,261	341		1,602
Total assets	$ 450,530	$ 734,005	$ (541,262)	$ 643,273
LIABILITIES AND PARTNERS EQUITY				
Current liabilities:				
Accounts payable	$	$ 10,238	$	$ 10,238
Accrued interest	7,498	19		7,517
Deferred revenue		10,437		10,437
Accrued property taxes		1,990		1,990
Other current liabilities	1,011	251		1,262
Total current liabilities	8,509	22,935		31,444
Long-term debt	332,649	158,999		491,648
Other long-term liabilities		10,809		10,809
Partners equity	109,372	541,262	(541,262)	109,372
Total liabilities and partners equity	$ 450,530	$ 734,005	$ (541,262)	$ 643,273

Condensed Consolidating Statement of Income

Year Ended December 31, 2011	Parent	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
Revenues:				
Affiliates	$	$ 167,626	$	$ 167,626
Third parties		45,923		45,923
		213,549		213,549
Operating costs and expenses:				
Operations		62,202		62,202
Depreciation and amortization		33,150		33,150
General and administrative	3,902	2,674		6,576
	3,902	98,026		101,928
Operating income (loss)	(3,902)	115,523		111,621
Equity in earnings of subsidiaries	106,393		(106,393)	
Equity in earnings of SLC Pipeline		2,552		2,552
Interest expense, net	(24,494)	(11,465)		(35,959)
Other income		17		17
	81,899	(8,896)	(106,393)	(33,390)
Income before income taxes	77,997	106,627	(106,393)	78,231
State income tax		(234)		(234)
Net income	$ 77,997	$ 106,393	$ (106,393)	$ 77,997

Condensed Consolidating Statement of Income

Year Ended December 31, 2010	Parent	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
Revenues:				
Affiliates	$	$ 146,376	$	$ 146,376
Third parties		35,721		35,721
		182,097		182,097
Operating costs and expenses:				

Operations		52,947		52,947
Depreciation and amortization		30,682		30,682
General and administrative	5,053	2,666		7,719
	5,053	86,295		91,348
Operating income (loss)	(5,053)	95,802		90,749
Equity in earnings of subsidiaries	87,280		(87,280)	
Equity in earnings of SLC Pipeline		2,393		2,393
Interest expense, net	(23,358)	(10,636)		(33,994)
Other income		17		17
	63,922	(8,226)	(87,280)	(31,584)
Income before income taxes	58,869	87,576	(87,280)	59,165
State income tax		(296)		(296)
Net income	$ 58,869	$ 87,280	$ (87,280)	$ 58,869

Condensed Consolidating Statement of Income

Year Ended December 31, 2009	Parent	Guarantor Subsidiaries	Non-Guarantor (In thousands)	Eliminations	Consolidated
Revenues:					
Affiliates	$	$ 101,395	$	$	$ 101,395
Third parties		45,166			45,166
		146,561			146,561
Operating costs and expenses:					
Operations		44,003			44,003
Depreciation and amortization		26,714			26,714
General and administrative	4,697	2,889			7,586
	4,697	73,606			78,303
Operating income (loss)	(4,697)	72,955			68,258
Equity in earnings of subsidiaries	81,773	3,686		(85,459)	
Equity in earnings of SLC Pipeline		1,919			1,919
SLC Pipeline acquisition costs		(2,500)			(2,500)
Interest expense, net	(11,062)	(10,428)			(21,490)
Other income		67			67
	70,711	(7,256)		(85,459)	(22,004)
Income from continuing operations before income taxes	66,014	65,699		(85,459)	46,254
State income tax		(20)			(20)
Income from continuing operations	66,014	65,679		(85,459)	46,234
Income from discontinued operations		16,094	5,265	(1,579)	19,780
Net income	$ 66,014	$ 81,773	$ 5,265	$ (87,038)	$ 66,014

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2011	Parent	Guarantor Subsidiaries (In thousands)	Eliminations	Consolidated
Cash flows from operating activities	$ 11,666	$ 81,453	$	$ 93,119
Cash flows from investing activities				

Additions to properties and equipment		(39,337)		(39,337)
Cash flows from financing activities				
Net borrowings under credit agreement		41,000		41,000
Repayments on promissory notes		(77,100)		(77,100)
Proceeds from issuance of common units	75,815			75,815
Capital contribution from general partner	5,887			5,887
Distributions to unitholders	(91,506)			(91,506)
Purchase of units for incentive grants	(1,641)			(1,641)
Deferred financing costs		(3,150)		(3,150)
Other	(221)			(221)
	(11,666)	(39,250)		(50,916)
Cash and cash equivalents				
Increase (decrease) for the year		2,866		2,866
Beginning of year	2	401		403
End of year	$ 2	$ 3,267	$	$ 3,269

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2010	Parent	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
Cash flows from operating activities	$ (59,916)	$ 163,084	$	$ 103,168
Cash flows from investing activities				
Additions to properties and equipment		(25,103)		(25,103)
Acquisition of assets from HFC		(35,526)		(35,526)
		(60,629)		(60,629)
Cash flows from financing activities				
Net repayments under credit agreement		(47,000)		(47,000)
Net proceeds from issuance of senior notes	147,540			147,540
Distributions to unitholders	(84,426)			(84,426)
Purchase price in excess of transferred basis in assets acquired from HFC		(57,560)		(57,560)
Purchase of units for incentive grants	(2,704)			(2,704)
Deferred financing costs	(494)			(494)
	59,916	(104,560)		(44,644)
Cash and cash equivalents				
Decrease for the year		(2,105)		(2,105)
Beginning of year	2	2,506		2,508
End of year	$ 2	$ 401	$	$ 403

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2009	Parent	Guarantor Subsidiaries	Non-Guarantor	Eliminations	Consolidated
			(In thousands)		
Cash flows from operating activities	$ (131,123)	$ 196,205	$ 6,613	$ (3,500)	$ 68,195
Cash flows from investing activities					
Additions to properties and equipment		(32,999)			(32,999)
Acquisitions of assets from HFC		(95,080)			(95,080)
Acquisition of assets from Sinclair		(25,665)			(25,665)
Investment in SLC Pipeline		(25,500)			(25,500)

Proceeds from sale of interest in Rio Grande, net of transferred cash		31,865			31,865
Other		3,174	(3,174)		
		(144,205)	(3,174)		(147,379)
Cash flows from financing activities					
Net borrowings under credit agreement		6,000			6,000
Proceeds from issuance of common units	186,801	(53,500)			133,301
Capital contribution from general partner	3,812				3,812
Distributions to unitholders	(61,188)		(5,000)	5,000	(61,188)
Distributions to noncontrolling interest				(1,500)	(1,500)
Net purchase price in excess of transferred basis in assets acquired from HFC	2,580	(5,700)			(3,120)
Purchase of units for incentive grants	(616)				(616)
Other	(266)				(266)
	131,123	(53,200)	(5,000)	3,500	76,423
Cash and cash equivalents					
Decrease for the year		(1,200)	(1,561)		(2,761)
Beginning of year	2	3,706	1,561		5,269
End of year	$ 2	$ 2,506	$	$	$ 2,508

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

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

Item 9A. Controls and Procedures

(a) Evaluation of disclosure controls and procedures

Our principal executive officer and principal financial officer have evaluated, as required by Rule 13a-15(b) under the Securities Exchange Act of 1934 (the Exchange Act), our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this annual report on Form 10-K. Our disclosure controls and procedures are designed to provide reasonable assurance that the information we are required to disclose in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of December 31, 2011 at a reasonable level of assurance.

(b) Changes in internal control over financial reporting

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

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

Item 9B. Other Information

There have been no events that occurred in the fourth quarter of 2011 that would need to be reported on Form 8-K that have not been previously reported.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Holly Logistic Services, L.L.C. (HLS), as the general partner of HEP Logistics Holdings, L.P. (HEP Logistics), our general partner, manages our operations and activities on our behalf. Our general partner is not elected by our unitholders. Unitholders are not entitled to elect the directors of HLS or directly or indirectly participate in our management or operations. The sole member of HLS, which is a subsidiary of HFC, appoints our directors to serve until their death, resignation or removal. Our general partner owes a fiduciary duty to our unitholders. Our general partner is liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically non-recourse to it. Whenever possible, our general partner intends to incur indebtedness or other obligations that are non-recourse.

Board Leadership Structure

The Board of Directors of HLS (the Board) believes that HLS s Chief Executive Officer is best situated to serve as Chairman of the Board because he is the director most familiar with HLS and HEP s business and industry, and most capable of effectively identifying strategic priorities and leading the discussion and execution of strategy. Independent directors and management have different perspectives and roles in strategy development. The independent directors on the Board bring experience, oversight and expertise from outside HLS, HEP and the industry, while the Chief Executive Officer brings HLS and HEP-specific experience and expertise. The Board believes that the combined role of Chairman of the Board and Chief Executive Officer promotes strategy development and execution and facilitates information flow between management and the Board, which are essential to effective governance of HLS and HEP.

One of the key responsibilities of the Board is to develop strategic direction and hold management accountable for the execution of strategy once it is developed. The Board believes the combined role of Chairman of the Board and Chief Executive Officer working with the lead independent director (the Presiding Director) is in the best interest of unitholders because it provides the appropriate balance between strategy development and independent oversight of management.

Presiding Director

Charles M. Darling, IV, an independent director who serves as Chairman of the compensation committee of the HLS Board, was appointed by the non-management directors of HLS to serve as the Presiding Director of the Board. The Presiding Director has the responsibility of presiding at all executive sessions of the non-management directors of the Board, consulting with management on Board and committee meeting agendas, acting as a liaison in appropriate instances between management and the non-management directors, including advising the Chairman of the Board and Chief Executive Officer on the efficiency of the Board meetings, and facilitating teamwork and communication between the non-management directors and management.

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

Risk Management

The Board has an active role, as a whole and also at the committee level, in overseeing management of the risks affecting HLS and HEP. The Board regularly reviews information regarding HLS and HEP s credit, liquidity and operations, as well as the risks associated with each. The compensation committee is responsible for overseeing the management of risks relating to HLS s executive compensation plans and arrangements. The audit committee oversees management of financial reporting and controls risks. The sole member of HLS manages risks associated with the independence of the Board and potential conflicts of interest. While each committee is responsible for evaluating certain risks and overseeing the management of such risks, the entire Board is regularly informed through committee reports about such risks.

The audit committee and the Board also receive input and reports from HLS s risk management oversight committee, made up of management personnel, none of whom serve on the Board and who have a range of different backgrounds, skills and experiences with regard to the operational, financial and strategic risk profile of HLS and HEP. The risk committee monitors the risk environment for HLS and HEP as a whole, and reviews the activities that mitigate risks to an achievable and acceptable level.

Four members of the Board serve on the conflicts committee to review specific matters that the Board or the conflicts committee believes may involve conflicts of interest. The conflicts committee determines if the resolution of the conflict of interest is fair and reasonable to us. The members of the conflicts committee may not be officers or employees of HLS or directors, officers, or employees of its affiliates, and must meet the independence and experience standards established by the New York Stock Exchange and the Securities Exchange Act of 1934 (the Exchange Act) to serve on the audit committee of a board of directors. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties it may owe us or our unitholders. In addition, we have an audit committee consisting of three independent directors that reviews our external financial reporting, selects our independent registered public accounting firm, and reviews procedures for internal auditing and the adequacy of our internal accounting controls. We also have a compensation committee consisting of three independent directors, which oversees compensation decisions for officers of HLS whose time is fully committed to us and, in 2011, oversaw a portion of the long-term incentive compensation of other officers who only devoted part of their time to the matters of HEP but who, based on their roles, were deemed by the compensation committee and the Board to be entitled to receive long-term incentive compensation from HEP with respect to their services. The compensation committee, with the assistance of the independent compensation consultant selected by the compensation committee, also oversees the compensation plans described below. In addition, we have an executive committee of the Board consisting of two independent directors and the Chairman of the Board.

The Board has determined that Messrs. Darling, Gray, Pinkerton and Stengel meet the applicable criteria for independence under the currently applicable rules of the New York Stock Exchange and under the Exchange Act. Messrs. Darling, Pinkerton and Stengel serve as the only members of our audit and compensation committees, and Messrs. Darling, Gray, Pinkerton and Stengel serve as the only members of our conflicts committee.

We are managed and operated by the directors and officers of HLS on behalf of our general partner. Most of our operational personnel are employees of HLS.

Prior to July 1, 2011, Mr. Matthew Clifton spent approximately 25% of his time overseeing the management of our business and affairs. Beginning July 1, 2011, Mr. Clifton spends approximately 50% of his time overseeing the management of our business and affairs. Mr. Mark Cunningham spends, and Mr. David Blair (until his departure from HLS) spent, all of their time in the management of our business. The rest of our officers devote as much of their time to us as is necessary to manage the day-to-day business of HLS and HEP.

The following table shows information for the current directors and executive officers of HLS.

Name	Age	Position with HLS
Matthew P. Clifton	60	Chairman of the Board, Chief Executive Officer and President
Charles M. Darling, IV	63	Director
William J. Gray	71	Director
Michael C. Jennings	46	Director
Jerry W. Pinkerton	71	Director
P. Dean Ridenour	70	Director
William P. Stengel	63	Director
James G. Townsend	57	Director
Bruce R. Shaw	44	Senior Vice President and Chief Financial Officer
Mark T. Cunningham	52	Vice President, Operations
Denise C. McWatters	52	Vice President, General Counsel and Secretary
Scott C. Surplus	52	Vice President and Controller(1)

(1) Effective July 1, 2011, Mr. Surplus was designated as an executive officer of HLS.

Committee memberships as of the date of this Annual Report on Form 10-K are set forth below:

Name (1) (2)	**Executive**	**Audit**	**Compensation**	**Conflicts**
Matthew P. Clifton	C			
Charles M. Darling, IV		X	C	X
William J. Gray				X
Jerry W. Pinkerton	X	C	X	X
William P. Stengel	X	X	X	C

(1) Messrs. Jennings, Ridenour and Townsend are omitted from this table because they do not currently serve on any committees.

(2) A C indicates that the director serves as the chair of the committee. An X indicates membership on the committee.

The Board held thirteen meetings during 2011, with the audit committee, conflicts committee and compensation committee holding five, eight, and eight meetings, respectively. During 2011, each director attended at least 75% of the total number of meetings of the Board and the committees of the Board on which such director serves.

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

All our directors bring to the Board executive leadership experience derived from their service in the many areas detailed below for each director. Certain individual qualifications and skills of our directors that contribute to the Board s effectiveness as a whole are described in the following paragraphs.

The names of the current directors, along with biographical information, are set forth below.

Matthew P. Clifton was appointed as Chairman of the Board and Chief Executive Officer in March 2004 and was appointed as President in July 2011. He has been employed by Holly Corporation since 1980. Mr. Clifton served as President of Holly Corporation from 1995 to 2006, Chief Executive Officer of Holly Corporation from 2006 until the merger of Holly Corporation and Frontier Oil Corporation in July 2011, Chairman of the Board of Directors of Holly Corporation from 2007 until the merger of Holly Corporation and Frontier Oil Corporation in July 2011, and has served as Executive Chairman of HFC since the merger of Holly Corporation and Frontier Oil Corporation in July 2011. Mr. Clifton also has served as a director of Holly Corporation (and now HFC) since 1995. The Board elected Mr. Clifton to Chairman of the Board because he has extensive knowledge of operations of HLS and HEP, the refining industry and macro-economic conditions, as well as valuable industry relationships throughout the country. Mr. Clifton brings a unique and valuable perspective as well as an understanding of the HLS and HEP s history, culture, vision and strategy to the Board.

Charles M. Darling, IV was appointed as a member of the Board in July 2004. Mr. Darling has served as President of DQ Holdings, L.L.C., a venture capital investment and consulting firm focused primarily on opportunities in the energy industry, since August 1998. In addition, Mr. Darling was the General Manager of Desert Power, LP and of its General Partner, Desert Power, LLC, which was an indirect affiliate of DQ Holdings, LLC. In late 2006, Desert Power, LLC and Desert Power, LP, along with certain of their subsidiaries, filed for bankruptcy in Nevada. In late 2007, the bankruptcy court approved the plan of reorganization, which became final in accordance with its terms in early 2008. Mr. Darling also previously practiced law at the law firm of Baker Botts, L.L.P., for over 20 years. The sole member of HLS appointed Mr. Darling to serve as a director due to his director and executive managerial experience in public companies, his extensive financial experience, and his experience in dealing with legal, regulatory and risk matters affecting HLS and HEP due to his 20-year legal practice at a large, national law firm, his service as President and General Counsel of a publicly traded energy company with a publicly traded pipelines MLP, and his subsequent endeavors in the energy industry. Mr. Darling s leadership skills, management and legal experience make him particularly well suited to be our Presiding Director.

William J. Gray was appointed as a member of the Board in April 2008. Mr. Gray is a private consultant, a member of the New Mexico House of Representatives (since November 2006), and served as a director of Holly Corporation from September 1996 until May 2008. He also has served as a governmental affairs consultant for Holly Corporation since January 2003 and as a consultant to Holly Corporation from October 1999 through September 2001. Mr. Gray was employed by Holly Corporation for over 30 years and retired in October 1999 at which time Mr. Gray was Senior Vice President, Marketing and Supply. The sole member of HLS appointed Mr. Gray to serve as a director due to his forty years of experience in pipeline, refining, and marketing and supply, for his business and management expertise, and for his regulatory and governmental experience and perspective.

Michael C. Jennings was appointed as a member of the Board in October 2011. Mr. Jennings serves as the Chief Executive Officer and President of HFC since the merger of Holly Corporation and Frontier Oil Corporation in July 2011. Mr. Jennings previously served as the President and Chief Executive Officer of Frontier Oil Corporation from 2009 until the merger of Holly Corporation and Frontier Oil Corporation in July 2011 and as the Executive Vice President and Chief Financial Officer of Frontier Oil Corporation from 2005 until 2009. Mr. Jennings served as the Chairman of the Board of Directors of Frontier Oil Corporation from 2010 until the merger of Holly Corporation and Frontier Oil Corporation in July 2011 and served as a director of Frontier Oil Corporation from 2008 until July 2011. He currently serves as a director of ION Geophysical Corporation and HFC. The sole member of HLS appointed Mr. Jennings to serve as a director due to his extensive industry knowledge and experience and his knowledge of the day-to-day operations of HFC.

Jerry W. Pinkerton was appointed as a member of the Board in July 2004. Mr. Pinkerton retired in December 2003. From December 2000 to December 2003, Mr. Pinkerton served as a consultant to TXU Corp and from August 1997 to December 2000, Mr. Pinkerton served as Controller of TXU Corp. and its U.S. subsidiaries. Prior to such time, Mr. Pinkerton served as the Vice President and Chief Accounting Officer of ENSERCH Corporation and was employed for 26 years as an auditor by Deloitte Haskins & Sells, a predecessor firm of Deloitte & Touche, LLP, including 15 years as an audit partner. Mr. Pinkerton was on the board of directors of Animal Health International, Inc., and served as chairman of its audit committee, from May 2008 to June 2011. The sole member of HLS appointed Mr. Pinkerton to serve as a director due to his audit, accounting and financial reporting expertise and a level of financial sophistication that qualifies him as a financial expert for his role as the chairman of the audit committee. Due to his executive managerial experience with public companies and public accounting firms and his service on each of HLS s four committees, Mr. Pinkerton possesses business and management expertise, a broad range of expertise and knowledge of Board committee functions, providing an invaluable insight into HLS and HEP s business.

P. Dean Ridenour was appointed as a member of the Board in August 2004. Mr. Ridenour retired in February 2010. From January 2008 until February 2010, Mr. Ridenour provided consulting services to Holly Corporation, and served as Vice President and Chief Accounting Officer of Holly Corporation and HLS from January 2005 to January 2008. Mr. Ridenour served as Vice President, Special Projects of Holly Corporation from August 2004 to December 2004 and prior to becoming a full-time employee, provided full-time consulting services to Holly Corporation beginning in October 2002. Mr. Ridenour was employed for 34 years by Ernst & Young LLP, including 20 years as an audit partner, retiring in 1997. The sole member of HLS appointed Mr. Ridenour to serve as a director due to his management experience and his accounting and financial reporting expertise.

William P. Stengel was appointed as a member of the Board in July 2004. Mr. Stengel retired in May 2003. From 1997 to May 2003, Mr. Stengel served as Managing Director of the global energy and mining group at Citigroup/Citibank, N.A. The sole member of HLS appointed Mr. Stengel to serve as a director due to his executive management experience in public companies, banking and financial expertise, and general business and management expertise. Due to his service on each of HLS s four committees, Mr. Stengel possesses a broad range of expertise and knowledge of Board committee functions, providing an invaluable insight into HLS and HEP s business.

James G. Townsend was appointed as a member of the Board in January 2012. Mr. Townsend retired from HFC in December 2011. He was employed by Holly Corporation (and HFC) and/or HLS for more than 25 years. Mr. Townsend served as Vice President of Operations for HLS from 2004 to 2007 and was responsible for all pipeline and terminal operations for Holly Corporation prior to the formation of HEP. From 2008 until his retirement, Mr. Townsend served as Senior Vice President of UNEV Pipeline, LLC, a joint venture between Sinclair Oil Corporation and a subsidiary of HFC, and was responsible for the permitting, engineering and constructing of the new interstate pipeline system undertaken by UNEV Pipeline, LLC. The sole member of HLS appointed Mr. Townsend to serve as a director due to his knowledge of the operations of HFC, HLS and their subsidiaries, his 25 years of experience in the industry, and his business expertise.

None of our directors reported any litigation for the period from 2002 to 2012 that is required to be reported in this Annual Report on Form 10-K.

The names of the current executive officers, along with biographical information, are set forth below, except for that of Mr. Clifton which is included above.

Bruce R. Shaw was appointed Senior Vice President and Chief Financial Officer effective December 31, 2011. Mr. Shaw served as the Senior Vice President, Strategy and Corporate Development of HLS from the effective time of the merger between Holly Corporation and Frontier Oil Corporation in July 2011 until December 30, 2011 and currently serves as the Senior Vice President, Strategy and Corporate Development for HFC. Mr. Shaw served as Senior Vice President and Chief Financial Officer of HLS from January 2008 until June 30, 2011, as Vice President, Corporate Development for HLS from August 2004 to January 2007 and as Senior Vice President and Chief Financial Officer of Holly Corporation from 2008 until the effective time of the merger between Holly Corporation and Frontier Oil Corporation in July 2011. Mr. Shaw served on the Board from April 2007 to April 2008 and as Vice President, Special Projects for Holly Corporation from September 2007 to December 2007. Mr. Shaw briefly left Holly Corporation in June 2007 and served as President of Standard Supply and Distributing Company, Inc. and Bartos Industries, Ltd., two companies that are affiliated with each other in the heating, ventilation, and air conditioning industry. Mr. Shaw previously served Holly Corporation in various positions with increasing seniority from 1997 to 2007. Prior to joining the Holly Corporation, Mr. Shaw was a consultant at McKinsey and Company, a global management consulting firm.

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

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

Scott C. Surplus was appointed Vice President and Controller in June 2008. Mr. Surplus also serves in a similar capacity for HFC. He served Holly Corporation and HLS as Vice President, Risk Management from 2007 to 2008, Vice President, Financial Reporting from 2005 to 2007 and Vice President and Controller from 2004 to 2005. Prior to this, he served in many areas of accounting and finance during his 27 years at Holly Corporation (and HFC), including SEC and financial reporting, tax, treasury, and risk management.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires directors, executive officers and persons who beneficially own more than 10% of HEP s units to file certain reports with the SEC and New York Stock Exchange concerning their beneficial ownership of HEP s equity securities. Based on a review of these reports, other information available to us and written representations from reporting persons indicating that no other reports were required, all such reports concerning beneficial ownership were filed in a timely manner by reporting persons during the year ended December 31, 2011, except for an inadvertent omission from a Form 4 that was timely filed on July 6, 2011 by David Blair. Due to an administrative oversight, the Form 4 that was timely filed by Mr. Blair reported three transactions in the Partnership s common units related to his departure, but did not report the disposition of 3,144 common units that Mr. Blair agreed to forfeit when he departed from his position as President of HLS to lead the Asphalt and Heavy Fuels Division of HFC.

Audit Committee

The audit committee of HLS is composed of three directors who are not officers or employees of HLS or any of its subsidiaries or HFC or any of its subsidiaries. The Board has adopted a written charter for the audit committee, which is available on our website at www.hollyenergy.com. The Board has determined that Jerry W. Pinkerton, a member of the audit committee, is an audit committee financial expert (as defined by the SEC) and has designated Mr. Pinkerton as the audit committee financial expert. As indicated above, the Board has determined that Mr. Pinkerton meets the applicable criteria for independence under the currently applicable rules of the New York Stock Exchange and under the Exchange Act.

The audit committee selects our independent registered public accounting firm and reviews the professional services they provide. It reviews the scope of the audit performed by the independent registered public accounting firm, the audit report issued by the independent auditor, HEP s annual and quarterly financial statements, any material comments contained in the auditor s letters to management, HEP s internal accounting controls and such other matters relating to accounting, auditing and financial reporting as it deems appropriate. In addition, the audit committee reviews the type and extent of any non-audit work to be performed by the independent registered public accounting firm and its compatibility with their continued objectivity and independence.

Report of the Audit Committee for the Year Ended December 31, 2011

Management of Holly Logistic Services, L.L.C. is responsible for Holly Energy Partners, L.P. s internal controls and the financial reporting process. The audit committee selected Ernst & Young LLP, Independent Registered Public Accounting Firm, to audit the books, records and accounts of Holly Energy Partners, L.P. for the year ended December 31, 2011. Ernst & Young LLP is responsible for performing an independent audit of Holly Energy Partners, L.P. s consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board and to issue a report thereon as well as to issue a report on the effectiveness of Holly Energy Partners, L.P. s internal control over financial reporting. The audit committee monitors and oversees these processes.

The audit committee has reviewed and discussed Holly Energy Partners, L.P. s audited consolidated financial statements with management and Ernst & Young LLP. The audit committee has discussed with Ernst & Young LLP the matters required to be discussed by Statement on Auditing Standards No. 114, *The Auditor s Communication With Those Charged With Governance.* The audit committee has received the written disclosures and the letter from Ernst & Young LLP pursuant to Rule 3526 of the Public Company Accounting Oversight Board, *Communication With Audit Committees Governing Independence,* and has discussed with Ernst & Young LLP that firm s independence.

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

Based on the foregoing review and discussions and such other matters the audit committee deemed relevant and appropriate, the audit committee recommended to the Board that the audited consolidated financial statements of Holly Energy Partners, L.P. be included in Holly Energy Partners, L.P. s Annual Report on Form 10-K for the year ended December 31, 2011.

Members of the Audit Committee:

Jerry W. Pinkerton, Chairman

Charles M. Darling, IV

William P. Stengel

Code of Ethics

HEP has adopted a Code of Business Conduct and Ethics that applies to all officers, directors and employees, including the company s principal executive officer, principal financial officer, and principal accounting officer.

Available on our website at www.hollyenergy.com are copies of our Governance Guidelines, Audit Committee Charter, Compensation Committee Charter, and Code of Business Conduct and Ethics, all of which also will be provided in print without charge upon written request to the Vice President, Investor Relations at: Holly Energy Partners, L.P., 2828 N, Harwood, Suite 1300, Dallas, TX, 75201-1507. HEP intends to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding any amendment to, or any waiver of, a provision of its Code of Business Conduct and Ethics with respect to its principal financial officers by posting such information on this website.

Item 11. Executive Compensation

DIRECTOR COMPENSATION

Members of the Board who also serve as officers or employees of HLS or HFC do not receive additional compensation in their capacity as directors. The only officers of HLS or HFC who also served as a director of HLS during 2011 were Messrs. Clifton and Jennings.

Each director is fully indemnified by HLS for actions associated with being a director to the extent permitted under Delaware law.

For the year ended December 31, 2011, directors who were not officers or employees of HLS or HFC were compensated as follows:

Annual cash retainer (payable in four quarterly installments)	$ 50,000
Board meeting or committee meeting attended in person (also paid to non-members of committees who are invited to attend by such committee s chairman) (1)	$ 1,500
Telephonic special board or committee meetings (30 minutes or less)	$ 0
Telephonic special board or committee meetings (over 30 minutes)	$ 1,000
Each attended strategy meeting with HLS management	$ 1,500
Annual grant of restricted units under the Long-Term Incentive Plan (2)	$ 75,000
	$ 10,000

Special cash retainer for Chairpersons of committees (payable in four quarterly installments)

(1) Upon submission of appropriate documentation, directors also are reimbursed for reasonable out-of-pocket expenses in connection with attending board or committee meetings.
(2) On July 27, 2011, the Board approved an increase to the equity component of the compensation paid to directors who are not officers or employees of HLS or HFC from $50,000 to $75,000. As a result, each August 1, beginning August 1, 2011, directors receive an annual grant under the Holly Energy Partners, L.P. Long-Term Incentive Plan (Long-Term Incentive Plan) of restricted HEP units equal in value to $75,000 on the date of grant, with 100% vesting one year after the date of grant.

Restricted unit grants are based upon the market closing price of our common units on the day of the grant (or the last business day prior, if August 1 occurs on a non-business day). With respect to the restricted units, the units fully vest one year following the date of grant if the director continues serving on the Board until the end of the one-year vesting period. Accelerated vesting of all unvested units will occur upon a change in control of HFC, HLS, HEP or HEP Logistics. In addition, accelerated vesting of unvested units will occur on a pro-rata basis upon the director s death, total and permanent disability or retirement. Until such time as the restricted units are vested, the director shall be entitled to receive all distributions paid with respect to such units and any right to vote with respect to such units (vesting pursuant to death, disability or retirement are prorated).

For purposes of director restricted units, a change in control means, subject to certain specific exceptions set forth in the restricted unit agreements:

- a person or group of persons (other than HFC or any of its wholly-owned subsidiaries, or HLS, HEP, HEP Logistics or any of their subsidiaries becomes the beneficial owner of more than 40% of the combined voting power of the then outstanding securities of HFC, HLS, HEP, or HEP Logistics;

- a majority of HFC s Board of Directors is replaced during a 12-month period by directors who were not endorsed by two-thirds of the previous board members;

- the consummation of a merger, consolidation or recapitalization of HFC, HLS, HEP or HEP Logistics resulting in the holders of voting securities of HFC, HLS, HEP, or HEP Logistics as applicable, prior to the merger or consolidation owning less than 60% of the combined voting power of the voting securities of HFC, HLS, HEP, or HEP Logistics, as applicable, or a recapitalization of HFC, HLS, HEP, or HEP Logistics in which a person or group becomes the beneficial owner of securities of HFC, HLS, HEP, or HEP Logistics, as applicable, representing more than 40% of the combined voting power of the then outstanding securities of HFC, HLS, HEP, or HEP Logistics, as applicable;

- the holders of voting securities of HFC, HLS, HEP or HEP Logistics approve a plan of complete liquidation or dissolution of HFC, HLS, HEP, or HEP Logistics, as applicable; or

- the holders of voting securities of HFC, HLS, HEP or HEP Logistics approve the sale or disposition of all or substantially all of the assets of HFC, HLS, HEP, or HEP Logistics, as applicable, other than to an entity holding at least 60% of the combined voting power of the voting securities immediately prior to such sale or disposition.

The merger of Holly Corporation and Frontier Oil Corporation, which closed on July 1, 2011 (the HFC Merger), constituted a change in control for purposes of the director restricted units. Accordingly, the restricted HEP units granted to the non-management directors on August 1, 2010, which would have otherwise vested on August 1, 2011, vested on July 1, 2011.

The table below sets forth the compensation earned in 2011 by each of the directors who were not officers or employees of HLS or HFC:

Name (1)	Fees Earned or Paid in Cash	Stock Awards (2)	All Other Compensation (3)	Total
Charles M. Darling, IV	$ 100,000	$ 74,979	$ 0	$ 174,979
William Gray	$ 89,000	$ 74,979	$ 32,119	$ 196,098
Jerry W. Pinkerton	$ 100,000	$ 74,979	$ 0	$ 174,979
P. Dean Ridenour	$ 79,500	$ 74,979	$ 0	$ 154,479
William P. Stengel	$ 100,000	$ 74,979	$ 0	$ 174,979

(1) Mr. Clifton and Mr. Jennings are not included in this table because they receive no additional compensation for their services as directors of HLS since Mr. Clifton and Mr. Jennings are each an officer of HFC and Mr. Clifton is also an officer of HLS. Mr. Townsend is not included in this table because he did not serve as a director of HLS in 2011.

(2) Reflects the aggregate grant date fair value of all awards computed in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 718, determined without regard to forfeitures. See note 7 to our consolidated financial statements for the fiscal year ended December 31, 2011, for a discussion of the assumptions used in determining the FASB ASC Topic 718 grant date fair value of these awards. Each of the non-employee directors (who was a member of the Board in 2011) received an award of 1,374 restricted HEP units under the Long-Term Incentive Plan on August 1, 2011 with a grant date fair value of $74,979 (computed using the closing price of $54.57 on August 1, 2011) that will vest on August 1, 2012. As of December 31, 2011, these are the only restricted HEP units held by our non-employee directors. The fair market value of each restricted unit grant is amortized over the one year vesting period. As of December 31, 2011, Messrs. Darling, Gray, Pinkerton, Ridenour and Stengel each held 1,374 unvested restricted units.

(3) In addition to the $89,000 of director fees reflected in this table, Mr. Gray received $32,119 for consulting services provided by Mr. Gray to HFC during 2011. None of the consulting fees were paid by HEP.

COMPENSATION DISCUSSION AND ANALYSIS

This compensation discussion and analysis (CD&A) provides information about our compensation objectives and policies for the HLS officers who are our Named Executive Officers and is intended to place in perspective the information contained in the executive compensation tables that follow this discussion. We provide a general description of our compensation program and specific information about its various components. Additionally, we describe our policies relating to reimbursement to HFC for compensation expenses. Immediately following this CD&A is the Compensation Committee Report.

Overview

HEP is managed by HLS, the general partner of HEP Logistics, HEP s general partner. HLS is a subsidiary of HFC. The employees providing services to HEP are employed by HLS, as HEP itself has no employees. As of December 31, 2011, HLS had 215 employees that provided general, administrative and operational services to HEP.

For 2011, the Named Executive Officers of HLS are as follows:

Matthew P. Clifton, Chairman of the Board and Chief Executive Officer from January 1, 2011 through June 30, 2011 and Chairman of the Board, Chief Executive Officer and President effective July 1, 2011;

Douglas S. Aron, Executive Vice President and Chief Financial Officer from July 1, 2011 through December 30, 2011;

Bruce R. Shaw, Senior Vice President and Chief Financial Officer from January 1, 2011 through June 30, 2011, Senior Vice President, Strategy and Corporate Development from July 1, 2011 through December 30, 2011; and Senior Vice President and Chief Financial Officer effective December 31, 2011;

Mark T. Cunningham, Vice President, Operations;

Denise C. McWatters, Vice President, General Counsel and Secretary; and

David G. Blair, President from January 1, 2011 through June 30, 2011.

In connection with the closing of the HFC Merger, Mr. Blair s employment with HLS ended when he departed from his position as President of HLS to lead the Asphalt and Heavy Fuels Division of HFC. In addition, in connection with the closing of the HFC Merger, the Board appointed (a) Mr. Clifton to the position of President (in addition to his positions as Chairman of the Board and Chief Executive Officer) of HLS, (b) Mr. Aron to the position of Executive Vice President and Chief Financial Officer of HLS and (c) Mr. Shaw to the position of Senior Vice President, Strategy and Corporate Development of HLS, in each case effective as of July 1, 2011. Effective December 31, 2011, (x) Mr. Aron resigned as Executive Vice President and Chief Financial Officer of HLS, (y) Mr. Shaw was appointed as Senior Vice President and Chief Financial Officer of HLS, and (z) Mr. Shaw s former position as Senior Vice President, Strategy and Corporate Development of HLS was not filled and was therefore eliminated.

Of the Named Executive Officers, only Mr. Cunningham currently allocates 100% of his professional time to HLS (and therefore HEP). Prior to his departure from HLS, Mr. Blair allocated 100% of his professional time to HLS (and therefore HEP). The other Named Executive Officers split their professional time between HFC and HLS.

Under the terms of the Omnibus Agreement, we currently pay an annual administrative fee to HFC of $2,300,000 for the provision of general and administrative services for our benefit, which may be increased or decreased as permitted under the Omnibus Agreement. Additionally, we reimburse HFC for expenses incurred on our behalf. The administrative services covered by the Omnibus Agreement include, without limitation, the costs of corporate services provided to HEP by HFC such as accounting, tax, information technology, human resources, in-house legal support and limited outside legal support for general corporate and tax matters; office space, furnishings and equipment; and limited transportation of HEP executive officers and employees on HFC airplanes for business purposes. The partnership agreement provides that our general partner will determine the expenses that are allocable to HEP. See Item 13, Certain Relationships, Related Transactions and Director Independence of this Annual Report on Form 10-K for additional discussion of our relationships and transactions with HFC. None of the services covered by the administrative fee are assigned any particular value individually. Although certain Named Executive Officers provide services to both HFC and HEP, no portion of the administrative fee is specifically allocated to services provided by the Named Executive Officers to HEP; rather, the administrative fee covers services provided to HEP by HFC and, except as described below, there is no reimbursement by HEP for the cost of such services. With respect to equity compensation paid by HEP to the Named Executive Officers, HLS purchases the units, and HEP reimburses HLS for the purchase price of the units.

We reimbursed HFC for 100% of the compensation expenses incurred by HFC for salary, bonus, retirement and other benefits for 2011 provided to Mr. Blair (while he was employed by HLS) and Mr. Cunningham. For the same time periods, we reimbursed HLS for 100% of the expenses incurred in providing Messrs. Blair and Cunningham with long-term equity incentive compensation. All compensation paid to them is fully disclosed in the tabular disclosure following this CD&A.

Messrs. Clifton and Shaw and Ms. McWatters were compensated by HLS for the services they perform for HLS through awards of equity-based compensation granted pursuant to the Long-Term Incentive Plan in March 2011. None of the cash compensation paid, or other benefits made available to, Messrs. Clifton, Aron, and Shaw and Ms. McWatters by HFC was allocated to the services they provide to HLS and, therefore, only the Long-Term Incentive Plan awards granted to Messrs. Clifton and Shaw and Ms. McWatters are disclosed herein. Because the awards of equity-based compensation granted pursuant to the Long-Term Incentive Plan were granted prior to the closing of the HFC Merger, Mr. Aron did not receive any equity compensation for his services from HLS in 2011.

Objectives of Compensation Program

Our compensation program is designed to attract and retain talented and productive executives who are motivated to protect and enhance the long-term value of HEP for the benefit of its unitholders. Our objective is to be competitive with our industry and encourage high levels of performance from our executives.

The compensation committee of the Board (the Committee), which is comprised entirely of independent directors, administers the Long-Term Incentive Plan for certain HLS employees. The Committee determined and approved the long-term equity incentive compensation to be paid to each of the Named Executive Officers and the other elements of compensation (in addition to the long-term equity incentive compensation) to be paid to Messrs. Blair and Cunningham.

As to Mr. Blair (prior to his departure from HLS) and Mr. Cunningham, the Committee has not adopted any formal policies for allocating compensation among salaries, bonuses and long-term equity incentive compensation. Instead, the Committee attempts to balance the use of both cash and equity compensation in the total compensation package provided to Mr. Blair (prior to his departure from HLS), and Mr. Cunningham. For our other Named Executive Officers, the Committee attempts to utilize long-term equity incentive compensation to build value to both HEP and its unitholders. The Committee considers both recommendations by management and other factors in determining the final compensation factors that are appropriate for both HEP and each Named Executive Officer for which it is responsible. The Committee does not review or approve pension benefits for Named Executive Officers, and all pension and retirement benefits provided to the executives are the same pension benefits that are provided to HFC employees, which benefit arrangements are sponsored and administered entirely by HFC without input from HLS or the Committee.

In January and February 2011, the Committee, with the assistance of the Chief Executive Officer, reviewed the mix and level of cash and long-term equity incentive compensation for Messrs. Blair and Cunningham with a goal of providing sufficient current compensation to retain them, while at the same time providing incentives to maximize long-term value for HEP and its unitholders. The Committee, with the assistance of the Chief Executive Officer (other than as to the Chief Executive Officer), and, until his departure from HLS, Mr. Blair (other than as to the Chief Executive Officer and Mr. Blair), annually performs an internal review of each of the Named Executive Officers long-term incentive compensation to determine whether the executives are being provided with equity awards that are effective in motivating the Named Executive Officers to create long-term value for HEP. These long-term equity incentives are designed to retain the executives for the period of time during which their performance is expected to impact our business and reward them in accordance with the success of those long-term goals and policies.

Role of the Compensation Committee Consultant and the Committee in the Compensation Setting Process

The Committee has engaged Frederic W. Cook & Co. (the Compensation Consultant), an outside consulting firm specializing in executive compensation, to advise the Committee on matters related to executive, long-term equity incentives, and non-employee director compensation. The Compensation Consultant provides the Committee with relevant market data, updates on related trends and developments, advice on program design, and input on compensation decisions for executive officers and non-employee directors. The Compensation Consultant is independent, retained directly by the Committee, and provides no other services to HLS or HEP. Until September 2011, the Compensation Consultant provided executive compensation consulting services to the Compensation Committee of the HFC Board of Directors, but the Compensation Consultant no longer provides such services to the Compensation Committee of the HFC Board of Directors. These services are further described in HFC s most recent proxy statement. No conflicts of interest exist between HLS, us or the Committee, on the one hand, and the Compensation Consultant, on the other hand.

The Compensation Consultant does not have authority to determine the ultimate compensation that is provided to employees or non-executive directors, and the Committee is under no obligation to utilize the information provided by the Compensation Consultant when making compensation decisions. The Compensation Consultant provides external context and other input to the Committee prior to the Committee meetings at which salaries and fees are approved, bonuses are awarded and equity compensation or awards are established for the upcoming year.

Review of Market Data

Market pay levels are one of many factors considered by the Committee in setting compensation for the Named Executive Officers, and we regularly review comparison data provided by the Compensation Consultant in regard to salary and annual incentive levels. This review provides a frame of reference as a starting point in evaluating the reasonableness and competitiveness of compensation within the sector of the energy industry with which we compete for executive talent, and to ensure that our compensation reflects practices of reasonably comparable companies of similar size and scope of operations. The Compensation Consultant obtains market information from various sources, including published compensation surveys (including, but not limited to, the *Liquid Pipeline Roundtable Compensation Survey)* and information taken from the SEC filings for groups of publicly traded organizations, as compiled by the Compensation Consultant, that we and the Compensation Consultant consider appropriate peer organizations. The purpose of the peer groups is to provide a frame of reference for our consideration of what compensation is appropriate for our executives and to ensure that our compensation is generally comparable to companies of similar size and scope of operations rather than to set specific benchmarks for the compensation provided to the Named Executive Officers and other executive officers. We look at peer groups that we believe provide relevant data points for our consideration.

The first peer group used by the Compensation Consultant in 2011 included publicly traded master limited partnerships that are representative of the types of companies with which we compete for executives.

Our 2011 peer group is as follows:

Company Name
Atlas Pipeline Partners, L.P.
Buckeye Energy Partners, L.P.
Copano Energy, L.L.C.
Crosstex Energy, L.P.
DCP Midstream Partners L.P.
Genesis Energy, L.P.
Inergy L.P.
Magellan Midstream Partners, L.P.
MarkWest Energy Partners, L.P.
NuStar Energy L.P.
Regency Energy Partners, L.P.
Sunoco Logistics Partners L.P.
Targa Resources Partners, L.P.

In addition, in 2011, we used a second peer group that was used by Holly Corporation for long-term incentive compensation as one reference point in our long-term incentive compensation decisions. In 2011, this peer group consisted of the following broader group of energy companies:

Company Name
Cameron International Corporation
CVR Energy, Inc.

El Paso Corporation

Exterran Energy Corp.

FMC Technologies, Inc.

Frontier Oil Corporation

Murphy Oil Corporation

Spectra Energy Corp.

Tesoro Corporation

The Williams Companies, Inc.

Western Refining, Inc.

Our objective generally is to position pay at levels approximately in the middle range of market practice, taking into account median levels derived from our peer group analyses. We consider our salary and non-salary compensation components in comparison to the median compensation levels within these peer groups rather than to an exact percentile above or below the median. If compensation is generally within plus or minus 20% of the market median, it is considered to be in the middle range of the market.

For each of the Named Executive Officers who committed all of his time to HEP in 2011 (i.e., Mr. Blair (until his departure from HLS) and Mr. Cunningham), total compensation (including cash and equity components of total compensation) was in the middle range of the market. As noted, however, this market analysis is just one of many factors considered when making overall compensation decisions for our executives. The range of various compensation elements for Messrs. Clifton, Aron and Shaw and Ms. McWatters will be discussed in further detail within the Compensation Discussion and Analysis section of HFC s 2012 proxy statement.

Role of Named Executive Officers in Determining Executive Compensation

In making executive compensation decisions, the Committee sought input from the Compensation Consultant, including the Compensation Consultant s input on peer group trends, and solicited the recommendations of our Chief Executive Officer, except with respect to his own compensation. In addition to the Compensation Consultant s information and various peer group trends, the Committee considered the Chief Executive Officer s recommendations in making its determinations of compensation. The Committee also reviewed the total compensation provided in the previous year in determining compensation to be paid in 2011 and established compensation for 2011 that was consistent with the compensation paid in 2010 after considering overall performance and the other specific factors discussed in this CD&A.

Various members of management facilitate the Committee s consideration of compensation for Named Executive Officers by providing data for the Committee s review. This data includes, but is not limited to, performance evaluations, performance compensation provided to the Named Executive Officers in previous years, tax-related considerations and accounting-related considerations. Management provides the Committee with guidance as to how such data impacts performance goals set by the Committee during the previous year. When management considers a discretionary bonus to be appropriate, it will suggest an amount and provide the Committee with management s rationale for such bonus. Given the day-to-day familiarity that management has with the work performed, the Committee values management s recommendations, although no Named Executive Officer will have any authority to determine or comment on compensation decisions directly related to him or herself. The Committee makes the final decision as to the compensation as described in this CD&A.

Overview of 2011 Executive Compensation Components

After reviewing the internal evaluations, the input by management, and the market data provided by the Compensation Consultant, the Committee believes that the 2011 compensation for each of Mr. Blair and Mr. Cunningham reflects an appropriate allocation of compensation between salary, bonuses and equity compensation.

For Mr. Blair and Mr. Cunningham, the components of compensation in 2011 were:

- base salary;
- annual performance-based cash incentive compensation;
- long-term equity incentive compensation;
- retirement and other post-employment benefits; and
- health and welfare benefits.

In 2011, the only component of compensation we provided for Messrs. Clifton and Shaw and Ms. McWatters (the other Named Executive Officers) was long-term equity incentive compensation. Each of Messrs. Clifton and Shaw s business time was spent primarily determining the long-term business goals and policies of HEP, while Ms. McWatters oversaw the legal matters for HEP. Accordingly, considering their performance of these functions during 2011, and the service coverage effected through the Omnibus Agreement, the Committee believed that it was appropriate to compensate them only through long-term equity incentives. Because the long-term equity awards were granted prior to the closing of the HFC Merger, Mr. Aron did not receive any equity compensation for his services from HLS in 2011. All Named Executive Officers receiving equity awards received HEP restricted units with the exception of Mr. Clifton, who only received an award of HEP performance units, and Mr. Blair, who received an award of both HEP restricted units and HEP performance units. The nature of each of these types of awards is more fully described below.

Base Salary

Base salaries for Messrs. Blair and Cunningham for 2011 were reviewed by the Committee based on each executive s position, level of responsibility and individual performance, and market practices. The Committee also reviewed competitive market data relevant to each position provided by the Compensation Consultant. Following a review of these various factors, the Committee determined that increases in the base salaries for Messrs. Blair and Cunningham were warranted for 2011. The base salaries for each of Messrs. Blair and Cunningham were increased three percent in 2011 in recognition of both increased responsibilities and excellent performance. The salary amounts for 2009, 2010 and 2011 for each of Messrs. Blair and Cunningham are set forth below in the Summary Compensation Table.

Annual Incentive Cash Bonus Compensation

The HLS Annual Incentive Plan (the Annual Incentive Plan) was adopted by the Board in August 2004 with the objective of motivating management and the employees of HLS and its affiliates who perform services for HLS and HEP to produce outstanding results collectively, encourage superior performance, increase productivity, contribute to the health and safety goals of HLS and HEP, and aid in attracting and retaining key employees. The Committee oversees the administration of the Annual Incentive Plan, and any potential awards granted pursuant to it are subject to final determination by the Committee that the performance goals for the applicable periods have been achieved.

The total bonus pool for all non-hourly personnel of HLS is established by the Committee after the end of each calendar year, giving consideration to amounts budgeted for the pool, operating results and employee performance. The awards to executives for a given year are paid in cash in the first quarter of the following year.

Payment with respect to cash bonuses to Mr. Blair and Mr. Cunningham is contingent upon the satisfaction of pre-established performance criteria as they apply to each of them, all of which are evaluated by management and incorporated into the recommendations made to the Committee. The amounts paid for 2011 are disclosed in the Summary Compensation Table and the bonuses are more fully described, including percentages of the bonuses that could be attributable to each performance criteria, in greater detail in the narrative following the 2011 Grants of Plan-Based Awards table. Generally, payment with respect to any 2011 cash bonus is contingent upon the satisfaction of the following criteria:

- A portion of the bonus is equal to a pre-established percentage of the employee s base salary and is earned based upon HEP s distributable cash flow compared to the 2011 operating budget adjusted for differences in estimated and actual PPI adjustments and differences in the timing of known acquisitions. The performance metric of distributable cash flow is used because it is a widely accepted financial indicator used to compare partnership performance. We believe that this measure provides an enhanced perspective of the operating performance of our assets and the cash our business is generating, and is therefore a useful criterion in evaluating management s performance and linking the payment of their bonus to our performance.

- A portion of the bonus is equal to a pre-established percentage of the employee s base salary, based on the employee s individual performance over the year. The employee s individual performance for 2011 is evaluated through an annual performance review completed in February 2012, which is a subjective and discretionary review of each applicable individual. The review includes a written assessment provided by the employee s immediate supervisor. The assessment reviews how well the employee displays each of the following competencies:

  - Individual Performance

  - Integrity

  - Interpersonal Effectiveness

Each one of these performance dimensions has a variety of sub-categories that are separately reviewed. The assessment also evaluates how well the employee performed their individual goals for 2011.

When the Committee established the 2011 performance criteria, the Committee determined that it could award a total of up to 200% of the total target bonus based on performance in excess of the targets, and the Committee communicated these maximum amounts and performance measures that would be potentially applicable to each executive officer.

The Committee also utilizes the analysis of the Compensation Consultant to determine how the compensation of Messrs. Blair and Cunningham, including bonus payments, compares to our peers and a market average. The annual incentive targets are assessed on the basis of total cash compensation, including base salary and annual incentive payments.

In addition to the pre-defined performance criteria, the Committee has discretion to approve an increase or a decrease in Mr. Cunningham s bonus, and prior to the end of his of employment with HLS, Mr. Blair s bonus. Increases and decreases are determined using the same factors that are used to establish bonuses, and poor results on the indicated factors could, in the discretion of the Committee, result in a decrease in a bonus. The Committee may consider other factors as well including, for example, environmental, health and safety. The Committee also considers whether conditions outside the control of the executives affected the factors. In cases where the performance objectives described above are achieved, yet the Committee believes additional compensation is warranted to reward an executive for outstanding performance, the Committee may award additional bonuses in its discretion. In making the determination as to whether such discretion should be applied (either to decrease a bonus or award additional bonuses), the Committee reviews recommendations from management. As a result of his departure from HLS, Mr. Blair received a lump sum payment of $80,000 (approximately 50% of his target annual bonus) and ceased to participate in the Annual Incentive Plan. The Committee awarded Mr. Cunningham s bonuses in recognition of the achievement of his performance targets, his impact on our improved financial results in 2011, the achievement of excellent safety results over a multi-year period and his efforts toward integration of several recent asset acquisitions. All 2011 bonuses will be paid in March 2012 (other than with respect to Mr. Blair, who received the lump sum payment discussed above).

The target and actual annual incentive cash bonus compensation awarded (and subsequently earned and payable) is described in the narrative to the section titled 2011 Grants of Plan-Based Awards .

The Committee has established 2012 performance goals for existing salary grades. Performance goals for all salary grades will remain the same in 2012 as those set for 2011.

Long-Term Incentive Equity Compensation

The Long-Term Incentive Plan was adopted by the Board in August 2004 with the objective of promoting the interests of HEP by providing to management, employees and consultants of HLS and its affiliates who perform services for HLS and HEP and its subsidiaries incentive compensation awards that are based on units of HEP. The Long-Term Incentive Plan also is contemplated to enhance our ability to attract and retain the services of individuals who are essential for the growth and profitability of HEP, to encourage them to devote their best efforts to advancing our business strategically, and to align their interests with those of our unit holders.

The Long-Term Incentive Plan contemplates four potential types of awards: restricted units (including fully vested and time vested bonus units), performance units, unit options and unit appreciation rights. Since the inception of HEP, we have made only restricted unit (including fully vested bonus units) and performance unit awards.

With respect to the Named Executive Officers, in determining the appropriate amount and type of long-term equity incentive awards to be made, the Committee considers the amount of time devoted by each executive to our business, the executive s position, scope of responsibility, base salary and available compensation information for executives in comparable positions in similar companies. The awards are granted annually during the first quarter of the year. Our goal is to reward the creation of value and high performance with variable compensation dependent on that performance. The total compensation may then be adjusted, including if the Committee observes a material variation from the market data (however, no specific formula is used to benchmark this data). The Committee believes this analysis verifies that total equity compensation to Messrs. Clifton, Shaw, Blair and Cunningham and Ms. McWatters is appropriate for the level of responsibility that each of these officers hold. For 2011, because the awards were granted during the first quarter of the year, which was prior to the closing of the HFC Merger, Mr. Aron did not receive any equity compensation for his services to HLS.

The HFC Merger and the subsequent departure of Mr. Blair from his role as President of HLS to lead the Asphalt and Heavy Fuels Division of HFC triggered the change in control provisions of the Long-Term Incentive Plan, which provisions have not been amended. As a result, at the time of his departure from HLS, the restricted units granted to Mr. Blair in 2009 and 2010 vested in full and the performance units granted to Mr. Blair in 2009 and 2010 were paid out at a performance percentage of 100% (rather than 150% as the Long-Term Incentive Plan provides in the event of a special involuntary termination). In addition, as discussed below, in connection with his departure from HLS, Mr. Blair agreed to forfeit the restricted units and performance units granted to him in 2011.

Restricted Unit Awards

A restricted unit award is an award of common units that is subject to forfeiture upon termination of employment prior to the vesting of the award. The Committee may approve grants on terms that it determines appropriate, including the period during which the award will vest. Under the Long-Term Incentive Plan, the Committee may condition vesting upon the achievement of specified financial objectives. The restricted units will vest upon a change of control of HEP, HEP Logistics, HLS or HFC, unless provided otherwise by the Committee in the agreement governing the award. The individual award agreements governing the restricted units granted to our Named Executive Officers have included an additional requirement that the vesting upon a change in control of HEP, HLS or HFC, as applicable, will be subject to the individual being terminated by us without cause or due to an adverse change in his or her employment relationship (the terms of which are described in greater detail in the Potential Payments Upon Termination or Change in Control below). This required condition for vesting to occur means that the restricted units are subject to a double-trigger vesting event rather than a single-trigger event as provided in the Long-Term Incentive Plan. However, the Long-Term Incentive Plan does allow us to provide for single-trigger change in control benefits in the event that the Committee has determined that the situation would be appropriate for any particular grant. In addition, the Committee may determine to eliminate the double-trigger requirement in future grants. Restricted unit holders have all the rights of a unit holder with respect to such restricted units, including the right to receive all distributions paid with respect to such restricted units and any right to vote with respect to the restricted units, subject to limitations on transfer and disposition of the units during the restricted period.

In 2011, the Named Executive Officers who were granted awards of restricted units were Messrs. Blair, Cunningham and Shaw and Ms. McWatters. All of the restricted units granted in 2011 vest in thirds over three annual periods and will be fully vested and nonforfeitable after December 31, 2013, as described in greater detail in the narrative in the section titled 2011 Grants of Plan-Based Awards. In connection with Mr. Blair s departure from HLS, pursuant to the Restricted Unit Agreement between HLS and Mr. Blair, dated as of March 1, 2011, Mr. Blair agreed to forfeit the restricted units granted to him in 2011 under the Long-Term Incentive Plan.

Performance Units

A performance unit is a notational phantom unit that entitles the grantee to receive a common unit upon the vesting of the unit or, as may be provided in the applicable agreement between the grantee and HLS, the cash equivalent to the value of a common unit. The grants made during 2011 are governed by award agreements that provide solely for settlement in units. Performance units will be settled only upon the attainment of pre-established performance targets. The Committee may approve grants on such terms as the Committee shall determine. The Committee approves the period over which performance units will vest, and the Committee may base its determination upon the achievement of specified financial objectives. As with restricted units, performance units may vest upon a change of control of HEP, HEP Logistics, HLS or HFC, unless provided otherwise by the Committee. The individual performance unit agreements provide for the double-trigger vesting provisions described above for the restricted units. Performance units are subject also to forfeiture in the event that the executive s employment or service relationship terminates for any reason, unless and to the extent that the Committee provides otherwise.

In 2011, performance units were awarded to Messrs. Clifton and Blair given their responsibilities to HEP with respect to long-term strategy. The performance period for such awards is from January 1, 2011 through December 31, 2013. Messrs. Clifton and Blair may earn no less than 50% and no more than 150% of the performance units subject to their awards over the course of the performance period as described more fully in the narrative in the section below titled 2011 Grant of Plan-Based Awards. The performance units currently outstanding may be settled only in common units of HEP. Prior to vesting, distributions are paid on each performance unit at the same rate as distributions paid on our common units. In connection with Mr. Blair s departure from HLS, pursuant to the Performance Unit Agreement between HLS and Mr. Blair, dated as of March 1, 2011, Mr. Blair agreed to forfeit the performance units granted to him in 2011 under the Long-Term Incentive Plan.

Acquisition of Common Units for Long-Term Incentive Equity Awards

Common units to be delivered in connection with the grant of performance unit awards may be common units acquired by HLS on the open market, common units already owned by HLS, common units acquired by HLS directly from us or any other person or any combination of the foregoing. We currently do not hold treasury units. HLS is entitled to reimbursement by us for the cost of acquiring the common units utilized for the grant of long-term incentive equity awards.

Tax and Accounting Implications

We account for the equity compensation expense for our employees and executive officers, including our Named Executive Officers, under the rules of FASB ASC Topic 718, which requires us to estimate and record an expense for each award of equity compensation over the vesting period of the award. Accounting rules also require us to record cash compensation as an expense at the time the obligation is accrued. Because we are a partnership, Section 162(m) of the Code does not apply to compensation paid to our Named Executive Officers. Accordingly, the Committee did not consider its impact in determining compensation levels for 2011. The Committee has taken into account the tax implications to the partnership in its decision to grant long-term incentive compensation awards of restricted and performance units as opposed to options or unit appreciation rights.

Retirement and Benefit Plans

The cost of retirement and welfare benefits for employees of HLS are charged monthly to us by HFC in accordance with the terms of the Omnibus Agreement. These employees participate in the health and welfare benefit plans available to our full-time employees, generally. In 2011, employees of HLS also participated in the Holly Corporation Retirement Plan (a tax qualified defined benefit plan) (the Holly Retirement Plan) and the Thrift Plan for employees of Holly Corporation (a tax qualified defined contribution plan now known as the HollyFrontier Corporation 401(k) Retirement Savings Plan) (the Holly Thrift Plan). The Holly Retirement Plan is described below in the narrative accompanying the Pension Benefits Table.

The Holly Thrift Plan is offered to all employees of HLS. Employees may, at their election, contribute to the Holly Thrift Plan amounts from 0% up to a maximum of 75% of their eligible compensation. In 2006, employees had the option to participate in both the Holly Retirement Plan and the Holly Thrift Plan. Effective January 1, 2007, the Holly Retirement Plan was frozen for new employees not covered by collective bargaining agreements with labor unions, and these new employees were required to participate in the new Automatic Thrift Plan Contribution feature under the Holly Thrift Plan (the amounts attributable to employer contributions for the Named Executive Officers are shown in the Summary Compensation Table below). To the extent an employee was hired prior to January 1, 2007, and elected to begin receiving the Automatic Thrift Plan Contribution under the Holly Thrift Plan, his participation in future benefits under the Holly Retirement Plan was frozen. For 2011, the Automatic Thrift Plan Contribution was up to 5% of eligible compensation, subject to applicable IRS limits and was paid in addition to employee deferrals and employer matching contributions under the Holly Thrift Plan.

In 2011, for employees not covered by collective bargaining agreements with labor unions, HFC provided matching of the employee s contributions to the Holly Thrift Plan equal to 100% of the first 6% of the employee s eligible compensation. Employee contributions that were made on a tax-deferred basis were generally limited to $16,500 per year, with employees 50 years of age or over able to make additional tax-deferred contributions of $5,500. Employer matching contributions for employees not covered by collective bargaining agreements with labor unions are vested immediately with no waiting period. Automatic Thrift Plan Contributions are still subject to a three year cliff vesting period.

Neither Messrs. Blair nor Cunningham elected to receive the Automatic Thrift Plan Contribution under the Holly Thrift Plan, and both remained in the Holly Retirement Plan that is discussed below in the section entitled Pension Benefits Table. Messrs. Blair (until his departure from HLS) and Cunningham are the only Named Executive Officers whose Holly Retirement Plan and Holly Thrift Plan benefits are charged to us by HFC. In 2011, Mr. Clifton participated in the Holly Retirement Plan and the Holly Retirement Restoration Plan. As of January 1, 2012, participants in the Holly Retirement Plan and the Holly Retirement Restoration Plan are no longer accruing additional benefits. Mr. Shaw formerly was a participant in the Holly Retirement Plan and has a Holly retirement benefit that was frozen in 2007. In 2011, Messrs. Clifton and Shaw and Ms. McWatters also participated in the Holly Thrift Plan and received matching contributions; however, Mr. Clifton did not receive the Automatic Thrift Plan Contribution because of his participation in the Holly Retirement Plan. Messrs. Clifton and Shaw and Ms. McWatters benefits are not charged to us by HFC. In 2011, Mr. Aron participated in the Frontier Oil Corporation retirement savings plan and nonqualified deferred compensation plan. Mr. Aron s benefits were not charged to us by HFC.

Change in Control Agreements

As of the date of this Annual Report on Form 10-K, neither we nor HLS has entered into any employment agreements with any of the Named Executive Officers. In 2008, Holly Corporation entered into Change in Control Agreements with Messrs. Blair and Cunningham, the costs of which were borne by Holly Corporation and were not reimbursable by us. Such Change in Control Agreements were terminated effective as of February 14, 2011 as a result of the adoption of the Holly Energy Partners, L.P. Change in Control Policy and the related form of Change in Control Agreement (discussed below). HFC historically had provided these agreements to Messrs. Blair and Cunningham to provide for management continuity in the event of a change of control and to provide competitive benefits for the recruitment and retention of executives; however, for reasons unrelated to the HFC Merger (which, in any event, would not have triggered the Holly Corporation Change in Control Agreements with Messrs. Blair and Cunningham), including the increased size of the business and employee base of HLS, the Board determined that HEP should adopt its own Change in Control Policy and Change in Control Agreements.

On February 14, 2011, the Board adopted the Holly Energy Partners, L.P. Change in Control Policy and the related form of Change in Control Agreement to be entered into between HEP and certain officers of HLS. The material terms of, and the quantification of, the potential amounts payable under the Change in Control Agreements are described below in the section titled Potential Payments upon Termination or Change in Control. The Change in Control Agreements contain double-trigger payment provisions that will not only require a change in control, but a qualifying termination of the executive prior to the individual becoming entitled to benefits pursuant to these agreements. Each of Messrs. Blair and Cunningham entered into a Change in Control Agreement with HEP, effective as of February 14, 2011, in accordance with the Holly Energy Partners, L.P. Change in Control Policy. HEP bears all costs and expenses associated with these agreements. The provisions of the Change in Control Agreements adopted by the Board on February 14, 2011 were not triggered as to either of Messrs. Blair or Cunningham as a result of the HFC Merger and subsequent events; and, as a result of Mr. Blair s departure from HLS, the Change in Control Agreement with Mr. Blair cannot be triggered in the future since both triggers of the double-trigger payment provision can no longer be satisfied. However, as mentioned above, the HFC Merger and the subsequent departure of Mr. Blair from his role as President of HLS to lead the Asphalt and Heavy Fuels Division of HFC triggered the change in control provisions of the Long-Term Incentive Plan, which provisions have not been amended.

HFC entered into Change in Control Severance Agreements with Mr. Clifton in May 2007 and Mr. Shaw and Ms. McWatters in January 2008, the costs of which are borne by HFC. The Change in Control Severance Agreements between HFC and each of Messrs. Clifton and Shaw and Ms. McWatters remain in effect. In 2008, Frontier entered into a Change in Control Severance Agreement with Mr. Aron, which remains in effect. The cost of Mr. Aron s Change in Control Severance Agreement is borne by HFC.

2012 Compensation Decisions

At its January 24, 2012 meeting, the Committee determined that beginning in 2012, Mr. Shaw and Ms. McWatters would no longer receive long-term equity incentive compensation from HEP for the services provided by Mr. Shaw and Ms. McWatters to HLS and HEP, and all compensation paid to them would instead be paid by HFC. In reaching this decision, the Committee considered the number of other similarly situated employees that provide services to HLS and HEP through the Omnibus Agreement without received long-term equity compensation from HEP. Based on such consideration, the Committee determined that Mr. Shaw and Ms. McWatters should be treated in a manner similar to such other shared employees.

At its February 21, 2012 meeting, the Committee determined that in 2012, Mr. Clifton s equity awards would be paid 75% in restricted units and 25% in performance units. In reaching this decision, the Committee considered the fact that 100% of Mr. Clifton s total equity compensation would be paid by HEP in 2012 as compared to 25% in prior years with the remaining 75% being paid by HFC. In addition, the Committee considered the amount of time Mr. Clifton devoted to our business and the type of equity compensation paid to other employees at HLS. Based on these factors, the Committee determined that granting Mr. Clifton both restricted units and performance units provided Mr. Clifton sufficient current compensation, while at the same time making a portion of his compensation contingent on maximizing long-term value for HEP and its unitholders.

Compensation Committee Report

The Compensation Committee of the Holly Logistic Services, L.L.C. Board of Directors has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussion, the Committee recommended to the Board that the Compensation Discussion and Analysis be included in this Form 10-K.

Members of the Compensation Committee:

Charles M. Darling, IV, Chairman

Jerry W. Pinkerton

William P. Stengel

SUMMARY COMPENSATION TABLE

The table below summarizes the total compensation paid or earned by each of the Named Executive Officers in 2011, 2010 and 2009. As previously noted, the cash compensation and benefits for Named Executive Officers other than Messrs. Blair and Cunningham were not paid by us, but rather by HFC, and were not allocated to the services those Named Executive Officers performed for us in 2011. Information regarding the compensation paid to Messrs. Clifton, Aron and Shaw and Ms. McWatters as consideration for the services they perform for HFC will be reported in HFC s 2012 proxy statement.

Summary Compensation Table

Name and Principal Position	Year	Salary	Bonus (1)	Stock Awards (2)	Non-Equity Incentive Plan Compensation (3)	Change in Pension Value (4)	All Other Compensation (5)	Total
Matthew P. Clifton,	2011			$ 588,501				$ 588,501
Chairman of the Board, Chief	2010			844,057				844,057
Executive Officer and President (6)	2009			500,018				500,018
Bruce R. Shaw,	2011			93,770				93,770
Senior Vice President and Chief	2010			93,783				93,783
Financial Officer (7)	2009			77,519				77,519
Mark T. Cunningham,	2011	$ 210,344(8)	$ 71,250	180,024	$ 58,750	$ 64,673	$ 12,600	597,641
Vice President Operations	2010	201,780	20,500	150,002	82,000	39,620	8,491	502,393
	2009	181,380		70,017	85,000	27,907	10,863	375,167
Denise C. McWatters,	2011			45,036				45,036
Vice President, General Counsel and	2010			45,018				45,018
Secretary(9)	2009			37,513				37,513
David G. Blair,	2011	176,198(10)	80,000(11)	393,834(12)		228,949	10,572	889,553
Former President	2010	312,000	44,000	393,800	156,000	153,366	13,253	1,072,419
	2009	274,851		310,030	210,000	100,105	14,700	909,686
Doug S. Aron	2011							

Former Executive Vice President
and Chief Financial Officer[13]

(1) Annual bonuses for services performed in 2011 will be paid in March 2012. Amounts in this column reflect the discretionary bonus, if any, payable pursuant to individual performance under our annual incentive bonus program and any other bonus paid outside our annual incentive bonus program. For Mr. Cunningham, the amount shown in this column also includes a one-time safety bonus of $12,500 awarded by the Committee to Mr. Cunningham based on Mr. Cunningham s achievement of excellent safety results over a multi-year period. For Mr. Blair, the amount shown in this column reflects a bonus of $80,000, or approximately 50% of his Target annual bonus, paid to Mr. Blair in connection with his departure from HLS.

(2) Amounts reported for stock awards in each of the 2011, 2010 and 2009 years represent the aggregate grant date fair value computed in accordance with FASB ASC Topic 718, determined without regard to forfeitures, and does not reflect the actual value that may be recognized by the executive. See notes 7, 6 and 7 to our consolidated financial statements for the fiscal years ended December 31, 2009, 2010 and 2011, respectively, for a discussion of the assumptions used in determining the FASB ASC Topic 718 grant date fair value of these awards. With respect to performance units, the amounts in the table above were based on an estimated payment of 110% of the award in each of 2009, 2010 and 2011 as this is the probable payout percentage for the performance units in such year and is consistent with the estimate of aggregate compensation cost to be recognized over the service period determined as of the grant date under FASB ASC Topic 718, excluding the effect of estimated forfeitures. If it is assumed that the performance units granted in 2011 would be paid out at the maximum payout level of 150%, Mr. Clifton would receive $802,531. In connection with the end of Mr. Blair s employment with HLS, pursuant to the Performance Unit Agreement between HLS and Mr. Blair, dated as of March 1, 2011, Mr. Blair agreed to forfeit performance units granted to him in 2011 under the Long-Term Incentive Plan. The terms of the 2011 performance unit awards and the 2011 restricted stock awards are provided below in the narrative following the 2011 Grants of Plan-Based Awards table. For additional information on restricted stock and performance unit awards, see below under 2011 Outstanding Equity Awards at Fiscal Year End. No other forfeitures of equity awards to the Named Executive Officers occurred in 2011.

(3) The annual bonus amounts for services performed in 2011 (paid in March 2012) reflect the actual bonuses payable to Mr. Cunningham pursuant to our annual incentive compensation program, the components of which are described below in greater detail in the narrative following the 2011 Grants of Plan-Based Awards table. Mr. Blair received a bonus of $80,000, or approximately 50% of his Target annual bonus, in connection with his departure from HLS and will not be entitled to receive a non-equity incentive plan bonus with respect to his services to HLS and HEP in 2011 or thereafter as a consequence of his prior services.

(4) The amounts shown in this column reflect the following assumptions:

	December 31, 2009	**December 31, 2010**	**December 31, 2011**
Discount Rate:	6.2%	5.65%	4.60%
Mortality Table:	RP2000 White Collar Projected to 2020 (50% Male/ 50% Female)	RP2000 White Collar Projected to 2020 (50% Male/ 50% Female)	2011 IRS Prescribed Mortality Static Annuitant, male and female
Retirement Age:	the later of current age or age 62	the later of current age or age 62	the later of current age or age 62

(5) This reflects matching contributions made to the Holly Thrift Plan by HLS, which were reimbursed by HEP (only applicable to Mr. Cunningham and Mr. Blair (through July 19, following which Mr. Blair s matching contributions were made by HFC)). Since Messrs. Blair and Cunningham elected to remain in the Holly Retirement Plan, as discussed in greater detail below in the section titled Pension Benefits Table, the only contributions are employer matching of employee contributions, subject to the limits described above in the section titled Retirement and Benefit Plans.

(6) Mr. Clifton served as Chairman of the Board and Chief Executive Officer until the effective time of the HFC Merger. Effective July 1, 2011, Mr. Clifton was named Chairman of the Board, Chief Executive Officer and President.

(7) Mr. Shaw served as Senior Vice President and Chief Financial Officer until June 30, 2011. Effective July 1, 2011, Mr. Shaw was named Senior Vice President, Strategy and Corporate Development, a

position which he held through December 30, 2011. Effective December 31, 2011, Mr. Shaw was named Senior Vice President and Chief Financial Officer and his former position as Senior Vice President, Strategy and Corporate Development of HLS was not filled and therefore eliminated.

(8) As of January 1, 2011, Mr. Cunningham s annual salary was $205,000. His annual salary was increased to $211,200 effective February 21, 2011. His actual payroll payments in 2011 were $210,007 due to our bi-weekly payroll system (the December 12, 2011 through December 25, 2011 payroll payment was made on January 3, 2012 and the December 26, 2011 through December 31, 2011 payroll payment was made on January 17, 2012). Similar adjustments were made for other mid-period pay adjustments in prior periods.

(9) The value of compensation received by Ms. McWatters from us does not exceed $100,000. Nevertheless, the value of the equity award granted to her by us has been included to provide investors with an understanding of the compensation provided to Ms. McWatters by us in consideration for her services to HEP. The inclusion of Ms. McWatters in our tabular disclosures has not resulted in the exclusion of any other executive officer from our executive compensation disclosures.

(10) As of January 1, 2011, Mr. Blair s annual salary was $312,000. His annual salary was increased to $321,400 effective February 21, 2011. Mr. Blair was employed by HLS through June 30, 2011, however, due to our bi-weekly payroll system, Mr. Blair was paid through July 10, 2011.

(11) Mr. Blair served as President until the effective time of the HFC Merger. As a result of his departure from his position as President of HLS to lead the Asphalt and Heavy Fuels Division of HFC, Mr. Blair received a lump sum payment of $80,000, which is equal to approximately 50% of his target annual bonus.

(12) While Mr. Blair received awards of restricted units and performance units in 2011, he forfeited those awards in connection with his departure from his position as President of HLS to lead the Asphalt and Heavy Fuels Division of HFC. Nevertheless, as required by SEC disclosure rules, the grant date fair value of the forfeited 2011 awards are reported in the table above.

(13) Effective July 1, 2011, Mr. Aron was named Executive Vice President and Chief Financial Officer. Mr. Aron held such position until December 30, 2011. As of December 31, 2011, Mr. Aron no longer serves as an officer of HLS.

2011 GRANTS OF PLAN-BASED AWARDS

The following table sets forth, for each Named Executive Officer, information about awards under our equity and non-equity incentive plans made during the year ending December 31, 2011. In this table, awards are abbreviated as AICP for the annual incentive cash compensation program, as RUA for restricted unit awards, and PUA for performance unit awards.

			Estimated Future Payouts Under Non-Equity Incentive Plan Awards (1)			Estimated Future Payouts Under Equity Incentive Plan Awards (2)			(i)	(k)
(a) Name	**Type**	**(b) Grant Date**	**(c) Threshold**	**(d) Target**	**(e) Maximum**	**(f) Threshold(#)**	**(g) Target (#)**	**(h) Maximum (#)**	**All other Equity Awards (3)**	**Grant Date Fair Value (4)**
Matthew P. Clifton	PUA	3/1/11				4,485	8,969	13,454		$ 588,501
Bruce R. Shaw	RUA	3/1/11							1,572	$ 93,770
Mark T. Cunningham	RUA	3/1/11							3,018	$ 180,024
	AICP			$ 84,480	$ 168,960					
Denise C. McWatters	RUA	3/1/11							755	$ 45,036
David G. Blair(5)	PUA	3/1/11				1,572	3,144	4,716		$ 206,294
	RUA	3/1/11							3,144	$ 187,540
	AICP			$ 160,700	$ 321,400					
Douglas S. Aron(6)										

(1) The amounts in columns (d) and (e) reflect the Target and Maximum bonus award amounts for Mr. Blair and Mr. Cunningham with respect to cash bonuses awarded pursuant to our Annual Incentive Plan in 2011 based on the percentages set forth below in the section titled Annual Incentive Cash Bonus Compensation. No Threshold is reported because our Annual Incentive Plan does not

specify a Threshold amount. The Target amount represents 50% and 40% of the base salaries of Messrs. Blair and Cunningham, respectively. The Maximum represents 200% of the respective employee s Target amount. As a result of his departure from HLS, Mr. Blair received a lump sum cash payment of $80,000, which is equal to approximately 50% of his target annual bonus.

(2) The amounts in columns (f), (g) and (h) represent the Threshold (50%), Target (100%) and Maximum (150%) payment levels with respect to grants of performance units in 2011. The Committee approved a grant of 8,969 performance units to Mr. Clifton and 3,144 performance units to Mr. Blair, the vesting schedules of which are described in the narrative below. In connection with the departure of Mr. Blair from HLS, Mr. Blair agreed to forfeit the performance units granted to him in 2011 under the Long-Term Incentive Plan.

(3) The Committee approved a grant of 3,144 restricted units to Mr. Blair, 3,018 restricted units to Mr. Cunningham, 1,572 restricted units to Mr. Shaw and 755 restricted units to Ms. McWatters, the vesting schedules of which are described in the narrative below. In connection with Mr. Blair s departure from HLS, Mr. Blair agreed to forfeit the restricted units granted to him in 2011 under the Long-Term Incentive Plan.

(4) This reflects the price of $59.65, the closing price at the close of business on February 28, 2011, the last business day immediately preceding the date of grant. The value of performance units was calculated using the $59.65 price based on an estimated payment of 110% of the award, which is the probable payout percentage for the performance units and is consistent with the estimate of aggregate compensation cost to be recognized over the service period determined as of the grant date under FASB ASC Topic 718, determined without regard to forfeitures. The assumptions used in calculating the assumed payout of performance units is discussed in footnote 2 to the Summary Compensation Table.

(5) While Mr. Blair received awards of restricted units and performance units in 2011, Mr. Blair agreed to forfeit those awards when he left his position as President of HLS in connection with the HFC Merger to lead the Asphalt and Heavy Fuels Division of HFC. However, as required by SEC disclosure rules, the grant date fair value of the forfeited 2011 awards are reported in the table above.

(6) Mr. Aron was named Executive Vice President and Chief Financial Officer effective July 1, 2011. Mr. Aron held such position until December 30, 2011. As of December 31, 2011, Mr. Aron no longer serves as an officer of HLS. He did not receive any plan-based awards in 2011.

The 2011 awards of performance units and restricted units were issued under our Long-Term Incentive Plan. The material terms of these awards are described below.

2011 Performance Units

Under the terms of the performance units granted to Messrs. Clifton and Blair in 2011, each employee may earn from 50% to 150% of the performance units, based on the total increase in our distributable cash flow per common unit. The performance period for the awards began on January 1, 2011 and ends on December 31, 2013. In connection with Mr. Blair s departure from HLS, pursuant to the Performance Unit Agreement between HLS and Mr. Blair, dated as of March 1, 2011, Mr. Blair agreed to forfeit performance units granted to him in 2011 under the Long-Term Incentive Plan. Following the completion of the performance period, Mr. Clifton shall be entitled to a payment of a number of common units equal to the result of multiplying his original grant amounts by the performance percentage set forth below:

Performance Unit Vesting Criteria

3-Year Total Increase in Distributable Cash Flow per Common Unit above $12.864	*Performance Percentage (%) to be Multiplied by Performance Units*
$0.00	*50%*
$1.057	*100%*
$2.170 or more	*150%*

In order to receive 100% of the units subject to this award, the distributable cash flow per common unit in the three years ended December 31, 2013 must total $13.92 per unit. In order to receive 150%, the distributable cash flow per common unit for the three years ended December 31, 2013 must total $15.03 per unit. The percentages are interpolated between points.

In the event that the employment of Mr. Clifton terminates prior to January 1, 2014, other than due to a special involuntary termination associated with a defined change-in-control event, an involuntary termination, death, disability or retirement, he will forfeit his award. In the event of the involuntary termination, death or total and permanent disability of Mr. Clifton, as determined by the Committee in its sole discretion, or upon Mr. Clifton s retirement after attaining age 62 or an earlier retirement age approved by the Committee in its sole discretion, Mr. Clifton will remain eligible to vest with respect to a pro rata number of units attributable to the period of service completed during the 36 month period (rounded up to include the month of termination) and will forfeit any unvested units. Any units that are not forfeited will become vested and payable based upon the performance actually achieved by us as of the end of the specified performance period. In its sole discretion, the Committee may make a payment assuming a performance percentage of up to 150% instead of the prorated number. As shown in the 2011 Grants of Plan-Based Awards table above, the amount shown in column (f) reflects the minimum payment amount of 50%, the amount shown in column (g) reflects the target payment amount of 100% and the amount shown in column (h) reflects the maximum payment amount of 150%.

Prior to vesting, distributions are paid on each performance unit at the same rate as distributions paid on our common units. The termination and change-in-control provisions of this award are described below under the section titled Potential Payments upon Termination or Change in Control. Additional information regarding the performance unit awards can be found above under Compensation Discussion and Analysis Long-Term Incentive Equity Compensation Performance Units.

2011 Restricted Units

Under the terms of the restricted units granted in 2011, except in the case of early termination, the restricted units become vested in accordance with the following schedule:

Restricted Unit Vesting Criteria

Vesting Date	*Cumulative Amount of Restricted Units Vested*
Immediately following December 31, 2011	*1/3*
Immediately following December 31, 2012	*2/3*
Immediately following December 31, 2013	*All*

Other than due to a special involuntary termination associated with a defined change-in-control event, death, disability or retirement, if an employee s employment is terminated prior to one of the vesting dates specified above, all unvested restricted units will be forfeited. In the event of the employee s death, total and permanent disability as determined by the Committee in its sole discretion, or upon either of the employee s retirement after attaining age 62 or an earlier retirement age approved by the Committee in its sole discretion, the employee will vest with respect to a pro rata number of units attributable to the period of service completed during the 36 month period (rounded up to include the month of termination) and will forfeit any unvested units. In its sole discretion, the Committee may decide to vest all of the units in lieu of the prorated number. Each listed employee is a unit holder with respect to all of the restricted units and has the right to receive all distributions paid with respect to such restricted units. The termination and change-in-control provisions of this award are described below in the section titled Potential Payments upon Termination or Change in Control.

In connection with Mr. Blair s departure from HLS, pursuant to the Restricted Unit Agreement between HLS and Mr. Blair, dated as of March 1, 2011, Mr. Blair agreed to forfeit the restricted units granted to him in 2011 under the Long-Term Incentive Plan.

Annual Incentive Cash Bonus Compensation

The cash bonuses that are available to our Named Executive Officers under the Annual Incentive Plan are based upon pre-set percentages of salary, achieved by reaching certain performance levels. A more detailed description of the pre-established performance criteria utilized in 2011 can be found above in the CD&A under the section titled Annual Incentive Cash Bonus Compensation. The following chart reflects the target percentages that were set for Messrs. Blair and Cunningham for 2011 (Messrs. Clifton, Aron and Shaw and Ms. McWatters do not receive cash bonuses under our Annual Incentive Plan).

Name and Principal Position	Actual Distributable Cash Flow vs. Budget	Individual Performance	Target Incentive Compensation (1)
David G. Blair, President	35%	15%	50%
Mark T. Cunningham, Vice President - Operations	20%	20%	40%

(1) Pursuant to our Annual Incentive Plan, the percentages with respect to the performance criteria identified in the first two columns actually achieved for each individual are added together and then multiplied by the base salary for each individual. The Target and Maximum awards are reflected above in the chart in the 2011 Grants of Plan Based Awards section. Neither of the listed employees received the Maximum awards. When the Committee established the 2011 performance criteria, the Committee determined that it could award a total of up to 200% of the total target bonus based on performance in excess of the targets (or 100% and 80% of the base salaries of Messrs. Blair and Cunningham, respectively). The Committee awarded Mr. Cunningham $117,500 pursuant to the Annual Incentive Plan in recognition of the achievement of his performance targets. In addition, the Committee awarded Mr. Cunningham a discretionary bonus of $12,500 as a one-time safety bonus based on Mr. Cunningham s achievement of excellent safety results over a multi-year period. As a result of his departure from HLS, Mr. Blair received a lump sum cash payment of $80,000, which is equal to approximately 50% of his Target annual bonus. Mr. Blair will not be entitled to receive any additional annual incentive bonus with respect to his services to HLS and HEP in 2011.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END

The following table sets forth, for each of our Named Executive Officers, information regarding restricted and performance units that were held as of December 31, 2011, including awards that were granted prior to 2011:

			Equity Awards (1)(2)	
Name	**Number of Units That Have Not Vested**	**Market Value of Units That Have Not Vested**	**Equity Incentive Plan Awards: Number of Unearned Units, Units or Other Rights That Have Not Vested**	**Equity Incentive Plan Awards: Market or Payout Value of Unearned Units, Units or Other Rights That Have Not Vested**
Matthew P. Clifton			64,487 (3)	$ 3,468,083
Bruce R. Shaw	4,149	$ 223,133		
Mark T. Cunningham	6,367	342,417		
Denise C. McWatters	1,996	107,345		
David G. Blair (4)				
Doug S. Aron				

(1) The values are based upon the closing market price of $53.78 on December 30, 2011 (the last business day in 2011).

(2) All awards are more particularly described in the text that immediately follows this chart.

(3) Includes 42,991 performance units which were multiplied by 1.5 because these performance units are subject to a maximum threshold of 150%. On January 25, 2011, the Committee determined that performance standards applicable to the vesting of the 7,802 restricted units granted to Mr. Clifton in 2005 had not been met, and, as a result, Mr. Clifton forfeited the 7,802 restricted units. In addition, on January 25, 2011, the Committee determined that the 10,522 performance units granted to Mr. Clifton in 2008 should be paid out at a performance percentage of 112%.

(4) In connection with Mr. Blair s departure from HLS, the restricted units granted to Mr. Blair in 2009 and 2010 vested in full, and Mr. Blair agreed to forfeit the restricted units granted to him in 2011. The performance units granted to Mr. Blair in 2009 and 2010 were paid out at

a performance

percentage of 100%, and Mr. Blair agreed to forfeit the performance units granted to him in 2011. In addition, on January 25, 2011, the Committee determined that the 3,815 performance units granted to Mr. Blair in 2008 should be paid out at a performance percentage of 112%, and effective January 1, 2011, the 1,271 restricted units granted to Mr. Blair in 2008 vested in full.

The following chart sets forth by year of grant the number of restricted and performance units awarded to our Named Executive Officers that remained outstanding as of December 31, 2011, and that are reflected in the immediately preceding chart:

Name	**2009 Restricted Units (1)**	**2009 Performance Units (2)**	**2010 Restricted Units (3)**	**2010 Performance Units (4)**	**2011 Restricted Units (5)**	**2011 Performance Units (6)**	**Total**
Matthew P. Clifton		21,460		12,562		8,969	42,991
Bruce R. Shaw	1,109		1,468		1,572		4,149
Mark T. Cunningham	1,001		2,348		3,018		6,367
Denise C. McWatters	536		705		755		1,996
David G. Blair							
Doug S. Aron							

(1) Under the terms of the March 2009 restricted unit grants, except in the case of early termination, the restricted units become vested in accordance with the following schedule:

Restricted Unit Vesting Criteria

Vesting Date	*Cumulative Amount of Restricted Units Vested*
Immediately following December 31, 2009	*1/3*
Immediately following December 31, 2010	*2/3*
Immediately following December 31, 2011	*All*

In its sole discretion, the Committee may decide to vest all of the units. Each listed employee is a unit holder with respect to all of the restricted units and has the right to receive all distributions paid with respect to such restricted units. The termination and change-in-control provisions of this award are described below under the section titled Potential Payments upon Termination or Change in Control. Effective January 1, 2012, the restricted units vested with respect to all the Named Executive Officers who received March 2009 restricted unit grants other than Mr. Blair. As a result of Mr. Blair s departure from HLS, pursuant to the Long-Term Incentive Plan and associated grant agreements, the remainder of the restricted units granted to Mr. Blair in 2009 vested in full.

(2) Mr. Clifton and Mr. Blair received awards of 21,460 and 6,653 performance units, respectively, in March 2009. Under the terms of the grant, the employees may earn from 50% to 150% of the performance units, based on the total increase in our cash distributions on our common units. The performance period for the award began on January 1, 2009 and ends on December 31, 2011. Following the completion of the performance period, the employees shall be entitled to payment of a number of common units equal to the result of multiplying the original grant amounts by the performance percentage set forth below:

Performance Unit Vesting Criteria

3-Year Total Increase in Cash Distributions Per Common Unit above $9.18 (1)	*Performance Percentage (%) to be Multiplied by Performance Units*
$0.00	*50%*
$0.658	*100%*
$1.346 or more	*150%*

(1) $9.18 represents a 3-year cumulative distribution of $3.06 per annum, $3.06 being the annual distribution rate in effect at the start of the performance period.

In order to receive 50% of the units subject to this award, the cash distributions per unit declared and paid in the three years ended December 31, 2011 must total $9.18 per unit. In order to receive 100%, the distributions per unit declared and paid for the three years ended December 31, 2011 must total $9.84 per unit. In order to receive 150%, the distributions per unit declared and paid in the three years ended December 31, 2011 must total $10.53 per unit. The percentages are interpolated between points.

In its sole discretion, the Committee may make a payment assuming a performance percentage of up to 150%. Prior to vesting, distributions are paid on each performance unit at the same rate as distributions paid on our common units. The termination and change-in-control provisions of this award are described below under the section titled Potential Payments upon Termination or Change in Control. On January 24, 2012, the Committee determined that the performance percentage applicable to these performance units was 109%, and Mr. Clifton was paid 23,391 common units in accordance with such determination. As a result of Mr. Blair s departure from HLS, pursuant to an agreement with HEP, the remainder of the performance units granted to Mr. Blair in 2009 under the Long Term Incentive Plan were paid out at a performance percentage of 100% (rather than 150% as the Long Term Incentive Plan provides in the event of a special involuntary termination).

(3) Under the terms of the March 2010 restricted unit grants, except in the case of early termination, the restricted units become vested in accordance with the following schedule:

Restricted Unit Vesting Criteria

Vesting Date	*Cumulative Amount of Restricted Units Vested*
Immediately following December 31, 2010	*1/3*
Immediately following December 31, 2011	*2/3*
Immediately following December 31, 2012	*All*

Each listed employee is a unit holder with respect to all of the restricted units and has the right to receive all distributions paid with respect to such restricted units. The termination and change-in-control provisions of this award are described below in the section titled Potential Payments upon Termination or Change in Control. As a result of Mr. Blair s departure from HLS, pursuant to the Long-Term Incentive Plan and the related grant agreement, the remainder of the restricted units granted to Mr. Blair under the Long-Term Incentive Plan in 2010 vested in full.

(4) Mr. Clifton and Mr. Blair received awards of 12,562 and 4,403 performance units, respectively, in March 2010. Under the terms of the grant, the employees may earn from 50% to 150% of the performance units, based on the total increase in our distributable cash flow per common unit. The performance period for the award began on January 1, 2010 and ends on December 31, 2012. Following the completion of the performance period, the employees shall be entitled to payment of a number of common units equal to the result of multiplying the original grant amounts by the performance percentage set forth below:

Performance Unit Vesting Criteria

3-Year Total Increase in Distributable Cash Flow Per Common Unit above $12.492 [(1)]	*Performance Percentage (%) to be Multiplied by Performance Units*
$0.00	*50%*
$1.026	*100%*
$2.107 or more	*150%*

(1) $12.492 represents a 3-year cumulative distributable cash flow per common unit of $4.164 per annum, $4.164 being the annual distributable cash flow per common unit rate in effect at the start of the performance period.

In order to receive 50% of the units subject to this award, the distributable cash flow per common unit for the three years ended December 31, 2012 must total $12.492 per unit. In order to receive 100%, the distributable cash flow per common unit for the three years ended December 31, 2012 must total $13.52 per unit. In order to receive 150%, the distributable cash flow per common unit for the three years ended December 31, 2012 must total $14.60 per unit. The percentages are interpolated between points.

In its sole discretion, the Committee may make a payment assuming a performance percentage of up to 150%. Prior to vesting, distributions are paid on each performance unit at the same rate as distributions paid on our common units. The termination and change-in-control provisions of this award are described below under the section titled Potential Payments upon Termination or Change in Control.

As a result of Mr. Blair s departure from HLS, pursuant to the Long-Term Incentive Plan and the related grant agreement, the performance units granted to Mr. Blair in 2010 under the Long-Term Incentive Plan were paid out at a performance percentage of 100% (rather than 150% as the Long-Term Incentive Plan provides in the event of a special involuntary termination).

(5) The vesting dates for the restricted units granted in March 2011 are described in the narrative disclosures in the section titled 2011 Grants of Plan-Based Awards under the heading Restricted Units.

(6) Messrs. Clifton and Blair received an award of performance units in March 2011. The vesting dates for this award are described in the narrative disclosures in the section titled 2011 Grants of Plan-Based Awards under the heading Performance Units.

2011 OPTION EXERCISES AND UNITS VESTED

The following table presents unit awards held by our Named Executive Officers that vested during 2011. To date, HEP has not granted any unit options.

	Unit Awards	
Named Executive Officer	Number of Units Acquired on Vesting	Value Realized on Vesting (1)
Matthew P. Clifton (2)	11,785	$ 612,820
Bruce R. Shaw (3)	3,479	177,116
Mark T. Cunningham (4)	2,792	142,141
Denise C. McWatters (5)	890	45,310
David G. Blair (6)	25,438	1,355,300
Doug S. Aron		

(1) Value realized from the vesting of restricted unit and/or performance unit awards is equal to the closing price of our common units on the vesting date (or, if the vesting date is not a trading date, on the trading date immediately prior to the date of vesting) multiplied by the number of vested units (calculated before payment of any applicable withholding or other income taxes).

(2) This amount includes 11,785 performance units that became payable to Mr. Clifton on January 26, 2011, when the closing price of HEP s common units was $52.00, upon the Committee s determination that the performance percentage applicable to 10,522 performance units granted to Mr. Clifton in March 2008 was 112%.

(3) The following restricted units previously granted to Mr. Shaw vested on January 1, 2011 (based on the closing price of HEP s common units on December 31, 2010 of $50.91 since January 1, 2011 was not a trading day): (a) 636 restricted units granted in March 2008; (b) 1,000 restricted units granted in April 2008; (c) 1,109 restricted units granted in March 2009; and (d) 734 restricted units granted in March 2010.

(4) The following restricted units previously granted to Mr. Cunningham vested on January 1, 2011 (based on the closing price of HEP s common units on December 31, 2010 of $50.91 since January 1, 2011 was not a trading day): (a) 616 restricted units granted in March 2008; (b) 1,002 restricted units granted in March 2009; and (c) 1,174 restricted units granted in March 2010.

(5) The following restricted units previously granted to Ms. McWatters vested on January 1, 2011 (based on the closing price of HEP s common units on December 31, 2010 of $50.91 since January 1, 2011 was not a trading day): (a) 537 restricted units granted in March 2009; and (b) 353 restricted units granted in March 2010.

(6) This amount includes:

(a) restricted units previously granted to Mr. Blair that vested on January 1, 2011 (based on the closing price of HEP s common units on December 31, 2010 of $50.91 since January 1, 2011 was not a trading day): (i) 1,271 restricted units granted in March 2008; (ii) 2,218 restricted units granted in March 2009; and (iii) 1,468 restricted units granted in March 2010.

(b) restricted units previously granted to Mr. Blair that vested on July 1, 2011 (based on a closing price of HEP s common units of $54.34): (i) 2,217 restricted units granted in March 2009; and (ii) 2,935 restricted units granted in March 2010.

(c) 4,273 performance units that became payable to Mr. Blair on January 26, 2011, when the closing price of HEP s common units was $52.00, upon the Committee s determination that the performance percentage applicable to 3,815 performance units granted to Mr. Blair in March 2008 was 112%.

(d) 6,653 performance units granted to Mr. Blair in March 2009 that became payable to Mr. Blair at 100% on July 1, 2011 upon his special involuntary termination from HLS (rather than 150% as the Long-Term Incentive Plan provides in the event of a special involuntary termination) when the closing price of HEP s common units was $54.34; and

(e) 4,403 performance units granted to Mr. Blair in March 2010 that became payable to Mr. Blair at 100% on July 1, 2011 upon his special involuntary termination from HLS (rather than 150% as the Long-Term Incentive Plan provides in the event of a special involuntary termination) when the closing price of HEP s common units was $54.34.

PENSION BENEFITS TABLE

In 2011, Mr. Clifton participated in the Holly Retirement Plan, which generally provides a defined benefit to participants following their retirement, and the Holly Retirement Restoration Plan, which provides supplemental retirement benefits to the participants in the plan. Mr. Cunningham and Mr. Blair also participated in the Holly Retirement Plan in 2011. As of January 1, 2012, participants in the Holly Retirement Plan and the Holly Retirement Restoration Plan are no longer accruing additional benefits. Mr. Shaw formerly was a participant in the Holly Retirement Plan and has a Holly retirement benefit that was frozen in 2007. In 2011, Mr. Aron did not participate in a defined benefit pension plan, although he participated in the tax-qualified and nonqualified defined contribution retirement savings plan previously maintained by Frontier Oil Corporation. The table below sets forth an estimate of the retirement benefits payable to Messrs. Blair and Cunningham at normal retirement age under the Holly Retirement Plan. Even though Mr. Clifton also participated in the Holly Retirement Plan, since we do not reimburse HLS for his pension benefits, which are instead paid for by HFC, we have not provided any disclosure with respect to his potential retirement benefits. The costs of the pension benefits for Mr. Blair (prior to his departure from HLS) were, and for Mr. Cunningham are, reimbursed to HLS on a current basis.

Pension Benefits

Name (a)	Plan Name (b)	Number of Years Credited Service (c)	Present Value of Accumulated Benefit (d)	Payments During Last Fiscal Year (e)
Matthew P. Clifton				
Bruce R. Shaw				
Mark T. Cunningham[(1)]	Retirement Plan	7.5	$ 177,958	$ 0
Denise C. McWatters				
David G. Blair	Retirement Plan	30.8	$ 992,629	$ 0
Douglas S. Aron				

(1) Mr. Cunningham is not eligible to commence receiving any benefit under the Holly Retirement Plan as of December 31, 2011. Since Mr. Blair is over age 50 and has more than 10 years of service, he is eligible for early retirement under the Holly Retirement Plan as of December 31, 2011. His early retirement benefit that would be payable had he elected to receive such a benefit beginning January 1, 2012 is estimated to be $5,865 per month payable for his lifetime or $1,109,403 payable as a lump sum.

The actuarial present value of the accumulated benefits reflected in the above chart was determined using the same assumptions as used for financial reporting purposes (which are discussed further in note 17 to HFC s consolidated financial statements for the fiscal year ended December 31, 2011, except the payment date was assumed to be age 62 for the Holly Retirement Plan rather than age 65. The earliest age at which a benefit can be paid with no benefit reduction under the Holly Retirement Plan is 62. In addition, the material assumptions used for these calculations include the following:

Discount Rate	4.60%
Mortality Table	2011 IRS Prescribed Mortality Static Annuitant, male and female

The amount of benefits accrued under the Holly Retirement Plan is based upon a participant s compensation, age and length of service. The compensation taken into account under the Holly Retirement Plan is a participant s average monthly compensation, which is based on an individual s base salary or base pay and any quarterly bonuses during the highest consecutive 36-month period of employment. No quarterly bonuses were provided to executives in 2011, but quarterly bonuses were paid to some non-executive union employees.

The Holly Retirement Plan provides for benefits upon normal retirement, early retirement, and late retirement, as well as providing accelerated deferred vested benefits, disability benefits, and death benefits. The normal retirement benefit under the plan may commence after an employee retires following his or her attainment of age 65. The normal form of payment is a monthly pension for the participant s life in an amount equal to (a) 1.6% of the participant s average monthly compensation multiplied by his or her total years of credited benefit service, minus (b) 1.5% of the participant s primary social security benefit multiplied by his or her total years of credited benefit service, such amount not to exceed 45% of the participant s primary social security benefit. Accrued benefits under the Holly Retirement Plan were frozen based on pay and service as of the close of business on December 31, 2011. In addition, a participant who (i) has attained age 50 and completed at least 10 years of service, or (ii) has attained age 55 and completed at least 3 years of service may elect to terminate employment and begin receiving benefits under the Holly Retirement Plan. If such a participant begins receiving benefits under the Holly Retirement Plan on or after the date the participant attains age 60 but before he reaches age 62, such benefits will be reduced by 1/12th of 21/2% for each full month that such benefits begin before age 62. If benefits begin before age 60, the participant s Holly Retirement Plan benefits will be reduced by 1/12th of 5% for each full month that such benefits begin before age 60.

An employee s benefit service is not deemed interrupted if the employee performed services for HFC and is later transitioned to work as an HLS employee. Instead of the normal form of payment, participants may also elect to receive their accrued benefits in the form of a life annuity with a period certain, a contingent annuity, or a lump sum. Participants in the cash balance feature of the Holly Retirement Plan were allowed to make a one-time irrevocable election during the 2009 year to freeze their benefit accruals under the Holly Retirement Plan and elect to participate in the automatic contribution feature under the defined contribution plan effective as of January 1, 2010, and participation under the cash balance feature was frozen to new employees; however, as previously noted, neither Messrs. Blair nor Cunningham elected to participate in such an option.

Benefits up to limits set by the Code are funded by HFC s contributions to the Holly Retirement Plan, with the amounts determined on an actuarial basis. In 2011, the Code limited benefits that could be covered by the Holly Retirement Plan s assets to $200,000 per year (subject to increases for future years based on price level changes) and limited the compensation that could be taken into account in computing such benefits to $250,000 per year (subject to certain upward adjustments for future years).

NONQUALIFIED DEFERRED COMPENSATION TABLE

Other than Mr. Aron, our Named Executive Officers did not participate in any nonqualified deferred compensation plan in 2011. In his capacity as an executive of HFC, Mr. Aron participated in the Frontier Oil Corporation Non-Qualified Deferred Compensation Plan in 2011. All benefits under the plan are paid by HFC and are not subject to reimbursement by HLS or HEP. A description of the Frontier Oil Corporation Non-Qualified Deferred Compensation Plan (and Mr. Aron s benefits thereunder) will be disclosed in HFC s 2012 proxy statement.

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

There are no employment agreements currently in effect between us and any Named Executive Officer. In 2008, Holly Corporation entered into Change in Control Agreements with Messrs. Blair and Cunningham, the costs of which were borne by Holly Corporation and were not reimbursable by us; however, such Change in Control Agreements were terminated effective as of February 14, 2011 as a result of the adoption of the Holly Energy Partners, L.P. Change in Control Policy and the related form of Change in Control Agreement (discussed below). HFC historically had provided these agreements to Messrs. Blair and Cunningham to provide for management continuity in the event of a change of control and to provide competitive benefits for the recruitment and retention of executives; however, for reasons unrelated to the HFC Merger (which, in any event, would not have triggered the Holly Corporation Change in Control Agreements with Messrs. Blair and Cunningham), including the increased size of the business and employee base of HLS, the Board determined that HEP should adopt its own Change in Control Policy and Change in Control Agreements. HFC entered into Change in Control Severance Agreements with Mr. Clifton in May 2007 and with Mr. Shaw and Ms. McWatters in January 2008, the costs of which also are borne by HFC. The Change in Control Severance Agreements between HFC and each of Messrs. Clifton and Shaw and Ms. McWatters remain in effect. In 2008, Frontier Oil Corporation entered into a Change in Control Severance Agreement with Mr. Aron, which was assumed by HFC and remains in effect. The cost of Mr. Aron s Change in Control Severance Agreement is borne by HFC. Because Messrs. Clifton, Aron and Shaw and Ms. McWatters do not perform services solely on behalf of HEP, a quantification of their potential benefits under their respective Change in Control Agreements is not provided below but will be disclosed in HFC s 2012 proxy statement. Further, the Change in Control Agreements with Messrs. Clifton, Aron and Shaw and Ms. McWatters trigger only upon a change in control of HFC.

On February 14, 2011, the Board adopted the Holly Energy Partners, L.P. Change in Control Policy and the related form of Change in Control Agreement to be entered into between HEP and certain officers of HLS. Each of Messrs. Blair and Cunningham entered into a Change in Control Agreement with HEP, effective as of February 14, 2011, in accordance with the Holly Energy Partners, L.P. Change in Control Policy adopted by the Board. The provisions of the Change in Control Agreements adopted by the Board on February 14, 2011 were not triggered as to either of Messrs. Blair or Cunningham as a result of the HFC Merger and subsequent events; and, as a result of the end of Mr. Blair s employment with HLS, the Change in Control Agreement with Mr. Blair cannot be triggered in the future since both triggers of the double trigger payment provision can no longer be satisfied. However, the HFC Merger and the subsequent departure of Mr. Blair from his role as President of HLS to lead the Asphalt and Heavy Fuels Division of HFC triggered the change in control provisions of the Long-Term Incentive Plan, which provisions have not been amended. The discussion below describes the Change in Control Agreement in effect between HEP and Mr. Cunningham as of December 31, 2011.

The Change in Control Agreement terminates on January 31, 2014, and thereafter automatically renews for one year terms (on each anniversary date thereafter) unless a cancellation notice is given by HEP 60 days prior to the automatic extension date. The Change in Control Agreement provides that if, in connection with or within two years after a Change in Control of HFC, HLS or HEP (1) the executive is terminated without Cause, leaves voluntarily for Good Reason, or is terminated as a condition of the occurrence of the transaction constituting the Change in Control, and (2) the executive is not offered employment with HFC, HLS, HEP, HEP Logistics or any of their affiliates on substantially the same terms in the aggregate as his previous employment with HLS within 30 days after the termination, then the executive will receive the following cash severance amounts paid by HEP as outlined in the table below:

a cash payment, paid within 10 days following the executive s termination, equal to his accrued and unpaid salary, unreimbursed expenses and accrued vacation pay, and

a lump sum amount, paid within 15 days following the executive s termination, equal to the multiple specified in the table below for such executive times (i) his annual base salary as of his date of termination or the date immediately prior to the Change in Control, whichever is greater, and (ii) his annual bonus amount, calculated as the average annual bonus paid to him for the prior three years. In addition, the executive (and his dependents, as applicable) will receive a continuation of their medical and dental benefits for the number of years indicated in the table below for such executive.

Named Executive Officer	Cash Severance Multiple	Years for Continuation of Medical and Dental Benefits
Mark T. Cunningham	1 times	1

For purposes of the Change in Control Agreement, a Change in Control occurs if:

- a person or group of persons (other than HFC or any of its wholly-owned subsidiaries or HLS, HEP, HEP Logistics or any of their subsidiaries becomes the beneficial owner of more than 50% of the combined voting power of the then outstanding securities of HFC, HLS, HEP or HEP Logistics or more than 50% of the outstanding common stock or membership interests, as applicable or HFC or HLS;

- a majority of HFC s Board of Directors is replaced during a 12-month period by directors who were not endorsed by a majority of the previous board members;

- the consummation of a merger, consolidation or recapitalization of HFC, HLS, HEP or HEP Logistics resulting in the holders of voting securities of HFC, HLS, HEP or HEP Logistics, as applicable, prior to the merger or consolidation owning less than 50% of the combined voting power of the voting securities of HFC, HLS, HEP or HEP Logistics, as applicable, or a recapitalization of HFC, HLS, HEP or HEP Logistics in which a person or group becomes the beneficial owner of securities of HFC, HLS, HEP or HEP Logistics, as applicable, representing more than 50% of the combined voting power of the then outstanding securities of HFC, HLS, HEP or HEP Logistics, as applicable;

- the holders of voting securities of HFC or HEP approve a plan of complete liquidation or dissolution of HFC or HEP, as applicable; or

- the holders of voting securities of HFC or HEP approve the sale or disposition of all or substantially all of the assets of HFC or HEP, as applicable, other than to an entity holding at least 60% of the combined voting power of the voting securities immediately prior to such sale or disposition.

For purposes of the Change in Control Agreement, Cause is defined as:

- the engagement in any act of willful gross negligence or willful misconduct on a matter that is not inconsequential; or

- conviction of a felony.

For purposes of the Change in Control Agreement, Good Reason is defined as, without the express written consent of the executive:

- a material reduction in the executive s (or his supervisor s) authority, duties or responsibilities;

- a material reduction in the executive s base compensation; or

- the relocation of the executive to an office or location more than 50 miles from the location at which the executive normally performed the executive s services, except for travel reasonably required in the performance of the executive s responsibilities.

All payments and benefits due under the Change in Control Agreement will be conditioned on the execution and non-revocation by the executive of a release of claims for the benefit of HFC, HLS, HEP and HEP Logistics and their related entities and agents. The Change in Control Agreement also contains confidentiality provisions pursuant to which each executive agrees not to disclose or otherwise use the confidential information of HFC, HLS, HEP or HEP Logistics. Violation of the confidentiality provisions entitles HFC, HLS, HEP or HEP Logistics to complete relief, including injunctive relief. Further, in the event of a breach of the confidentiality covenants, the executive could be terminated for Cause (provided the breach constituted willful gross negligence or misconduct on the executive s part that is not inconsequential). The agreements do not prohibit the waiver of a breach of these covenants.

If amounts payable to an executive under a Change in Control Agreement (together with any other amounts that are payable by HFC, HLS, HEP or HEP Logistics as a result of a change in ownership or control) (collectively, the Payments) exceed the amount allowed under section 280G of the Code for such executive (thereby subjecting the executive to an excise tax as described in further detail below) by 10% or more, HEP will pay the executive a tax gross up (a Gross Up) in an amount necessary to allow the executive to retain (after all regular income and Code Section 280G taxes) a net amount equal to the total present value of the Payments on the date they are to be paid (after all regular income taxes but without reduction for Code Section 280G taxes). Conversely, the Payments will be reduced to the level at which no excise tax applies if they exceed the Code Section 280G limit for the executive by less than 10% (a Cut Back).

In addition, under the terms of the long-term incentive equity awards described above in the section entitled Compensation Discussion and Analysis Long-Term Incentive Equity Compensation and in the narrative following the Grants of Plan Based Awards Table, if, in the event of a Change in Control , either sixty (60) days prior to the Change in Control event or at any time following such event, (i) a Named Executive Officer s employment is terminated, other than for cause, or (ii) he resigns within ninety (90) days following an Adverse Change (any such termination, a Special Involuntary Termination) then all restrictions on the award will lapse, the units will become vested and the vested units will be delivered to the Named Executive Officer as soon as practicable, though in no event following two and one-half months following the end of the year in which the Special Involuntary Termination occurs. All outstanding performance units will vest at 150% in the event of a Special Involuntary Termination.

Other than upon a Special Involuntary Termination, restricted units and performance units have slightly different accelerated vesting and forfeiture provisions upon certain terminations of employment. With regard to restricted units, if an executive dies, becomes totally and permanently disabled (as determined by the Committee in its sole discretion), or retires after attaining age 62 (or an earlier retirement age approved by the Committee), the executive will vest with respect to a pro rata number of units attributable to the period of service completed during the 36 month period (rounded up to include the month of termination) and will forfeit any unvested units. With regard to performance units, if an executive dies, becomes totally and permanently disabled (as determined by the Committee in its sole discretion), retires after attaining age 62 (or an earlier retirement age approved by the Committee), or separates from employment for any other reason other than a voluntary separation, Special Involuntary Separation or for Cause, then the executive will remain eligible to vest with respect to a pro rata number of units attributable to the period of service completed during the 36 month period (rounded up to include the month of termination) and will forfeit any unvested units. The Committee will determine the number of remaining performance units earned and the amount to be paid to the executive as soon as administratively possible after the end of the performance period based upon the performance actually attained for the entire performance period.

For purposes of the long-term equity incentive awards, a Change in Control occurs if:

- a person or group of persons (other than HFC or any of its wholly-owned subsidiaries or HLS, HEP, HEP Logistics or any of their subsidiaries) becomes the beneficial owner of more than 40% of the combined voting power of the then outstanding securities of HFC, HLS, HEP or HEP Logistics;

- a majority of HFC s Board of Directors is replaced during a 12-month period by directors who were not endorsed by two-thirds of the previous board members;

- the consummation of a merger, consolidation or recapitalization of HFC, HLS, HEP or HEP Logistics resulting in the holders of voting securities of HFC, HLS, HEP or HEP Logistics, as applicable, prior to the merger or consolidation owning less than 60% of the combined voting power of the voting securities of HFC, HLS, HEP or HEP Logistics, as applicable, or a recapitalization of HFC, HLS, HEP, or HEP Logistics in which a person or group becomes the beneficial owner of securities of HFC, HLS, HEP or HEP Logistics, as applicable, representing more than 40% of the combined voting power of the then outstanding securities of HFC, HLS, HEP or HEP Logistics, as applicable;

- the holders of voting securities of HFC, HLS, HEP or HEP Logistics approve a plan of complete liquidation or dissolution of HFC, HLS, HEP or HEP Logistics, as applicable; or

- the holders of voting securities of HFC, HLS, HEP or HEP Logistics approve the sale or disposition of all or substantially all of the assets of HFC, HLS, HEP or HEP Logistics, as applicable, other than to an entity holding at least 60% of the combined voting power of the voting securities immediately prior to such sale or disposition.

For purposes of the restricted unit awards, Adverse Change is defined as:

- a change in the city in which the executive is required to work;

- a substantial increase in travel requirements of employment;

- a substantial reduction in the duties of the type previously performed by the executive; or

- a significant reduction in compensation or benefits (other than bonuses and other discretionary items of compensation) that does not apply generally to executives.

For purposes of the performance unit awards, Adverse Change is defined as, without the consent of the executive:

- a change in the executive s principal office of employment of more than 25 miles from the executive s work address at the time of a grant of the equity award;

- a material increase (without adequate consideration) or material reduction in the duties to be performed by the executive; or

- a material reduction in the executive s base compensation (other than bonuses and other discretionary items of compensation or a general reduction applicable generally to executives).

For purposes of the long-term equity incentive awards, Cause is defined as:

- an act of dishonesty constituting a felony or serious misdemeanor and resulting (or intended to result in) gain or personal enrichment to the executive at the expense of HLS;

- gross or willful and wanton negligence in the performance of the executive s material and substantial duties; or

- conviction of a felony involving moral turpitude.

The following table reflects the estimated payments due pursuant to the Change in Control Agreements and the accelerated vesting of equity awards of each Named Executive Officer as of December 31, 2011, assuming, as applicable, that a Change in Control occurred (under both the Change in Control Agreements and the equity awards) and/or such executives were terminated effective December 31, 2011. For these purposes, our common unit price was assumed to be $53.78, which is the closing price per unit on December 30, 2011 (the last business day in 2011). The amounts below have been calculated using numerous assumptions that we believe are reasonable, such as the assumption that all reimbursable expenses were current as of December 31, 2011. Accrued vacation is not allowed to be carried over to a subsequent year, so we assumed all accrued vacation for the 2011 year was taken prior to December 31, 2011. Employees accrue vacation in 2011 for use in 2012, so we included the value of the 2011 accrued but unused vacation. However, any actual payments that may be made pursuant to the agreements described above are dependent on various factors, which may or may not exist at the time a Change in Control actually occurs and the Named Executive Officer is actually terminated. Therefore, such amounts and disclosures should be considered forward looking statements. Because vesting of the performance units upon a termination due to death, disability, retirement, or other separation (other than a voluntary separation, a for Cause separation or a Special Involuntary Termination) remains contingent upon the attainment of performance goals at the end of the applicable performance periods, no amounts associated with accelerated vesting of performance units under those circumstances have been included in the table below.

Named Executive Officer[1]	Cash Payments[2]	Value of Welfare Benefits[3]	Accelerated Vesting of Equity Awards	280G Excise Tax Gross Up or Cut Back[4]	Total[5]
Matthew P. Clifton					
Termination in connection with or following a Change in Control			$ 3,468,084[6]		$ 3,468,084
Termination due to Death, Disability or Retirement			0 [8]		0
Bruce R. Shaw					
Termination in connection with or following a Change in Control			223,133[7]		223,133
Termination due to Death, Disability or Retirement			127,297 [8]		127,297
Mark T. Cunningham					
Termination in connection with or following a Change in Control	$ 311,613	$ 21,708	342,417[7]		675,738
Termination due to Death, Disability or Retirement			171,074[8]		171,074
Denise C. McWatters					
Termination in connection with or following a Change in Control			107,345[7]		107,345
Termination due to Death, Disability or Retirement			61,363[8]		61,363

(1) Mr. Blair was omitted from this table since Mr. Blair s employment with HLS ended at the effective time of the HFC Merger. Although the provisions of Mr. Blair s Change in Control Agreement were not triggered as a result of the HFC Merger, the HFC Merger and the subsequent departure of Mr. Blair from his role as President of HLS to lead the Asphalt and Heavy Fuels Division of HFC triggered the change in control provisions of the Long-Term Incentive Plan. As a result, as has been described above, in connection with his departure, (1) the restricted units granted to Mr. Blair in 2009 and 2010 vested in full, (2) the performance units granted to Mr. Blair in 2009 and 2010 under the Long-Term Incentive Plan were paid out at a performance percentage of 100% (rather than 150% as the plan provides in the event of a special involuntary termination) and (3)Mr. Blair received a payment of $80,000 (approximately 50% of his target annual bonus). In addition, Mr. Blair agreed to forfeit the performance units and restricted units granted to him in 2011. The value of the accelerated vesting of Mr. Blair s equity awards was $600,783 (calculated by multiplying 11,056 units by the closing sales price of an HEP unit of $54.34 on July 1, 2011). Mr. Aron was omitted from this table since Mr. Aron does not hold any HEP equity awards. The potential benefits payable to him under his Change in Control Agreement will be disclosed in HFC s 2012 proxy statement.

(2) Represents cash payments equal to the sum of the executive s (a) accrued vacation as of December 31, 2011 ($16,246 for Mr. Cunningham), plus (b) base salary as of December 31, 2011 ($211,200 for Mr. Cunningham) times the multiplier applicable to the executive (one (1) for Mr. Cunningham), plus (c) average annual cash bonus paid for 2008, 2009 and 2010 ($84,167 for Mr. Cunningham) times the multiplier applicable to the executive (one (1) for Mr. Cunningham).

(3) Represents the value of the continuation of medical and dental benefits for each executive (and, as applicable, his spouse and dependents) for the length of one year multiplied by the applicable multiplier identified above. The amount was determined based upon the applicable COBRA rates for the employee s benefits. The value of the benefits was determined by using the current monthly premium amount for a similarly situated employee electing COBRA continuation coverage.

(4) As applicable, reflects the amount of the Tax Code Section 280G Gross Up payment or the amount subject to the Section 280G Cut Back. To determine whether any Gross Up or Cut Back applies, the base amount for each Named Executive Officer was calculated using the five-year average of each officer s compensation for the years 2006-2010. In the case of Ms. McWatters, the amount is calculated using her annualized compensation for 2007, since her employment with HFC commenced in October 2007. In the case of Mr. Shaw, the amount is calculated using his annualized compensation for 2007 because he left employment in May 2007 and returned in September 2007. Payments received in connection with a change in control in excess of a Named Executive Officer s base amount are considered excess parachute payments as provided by Section 280G of the Tax Code, if the total of all parachute payments received by the Named Executive Officer is equal to or greater than three times his or her base amount. Excess parachute payments will be subject to the excise tax. In making the calculation, the following assumptions were used: (a) the change in control occurred on December 31, 2011, (b) the closing price of our common units was $53.78 per unit on December 30, 2011 (the last business day in 2011), (c) the excise tax rate under Section 4999 of the Tax Code is 20%, the federal income tax rate is 35%, the Medicare rate is 1.45%, the adjustment to reflect the phase-out of itemized deductions is 1.05%, and there are no state or local income taxes, (d) no amounts will be discounted as attributable to reasonable compensation, (e) all cash severance payments are contingent upon a change in control, and (f) the presumption required under applicable regulations that the equity awards granted in 2011 were contingent upon a change in control could be rebutted.

(5) These payments reflect the application of any potential Gross Up or Cut Back. No Gross Up or Cut Back was applicable for any Named Executive Officer.

(6) Mr. Clifton held 42,991 performance units on December 31, 2011. Because Mr. Clifton is eligible to receive 150% of the performance units under the terms of the long-term incentive plan in the event of a Special Involuntary Termination, the amount included in the table was reached by multiplying his 42,991 performance units by 1.5, and then again by $53.78, the closing price of our units on December 30, 2011 (the last business day in 2011), to equal $3,468,084.

(7) Based upon a payment of the HEP restricted units as provided for under the terms of the long-term incentive equity agreements governing the awards of the units and based upon the closing price of HEP units on December 30, 2011 (the last business day in 2011) of $53.78. As of December 31, 2011, Mr. Shaw held 4,149 outstanding restricted units, Mr. Cunningham held 6,367 outstanding restricted units, and Ms. McWatters held 1,996 outstanding restricted units.

(8) As described above, restricted units are subject to pro rata vesting upon death, disability or retirement after age 62 (or an earlier retirement age approved by the Committee). Amounts are calculated based on the closing price of HEP units on December 30, 2011 (the last business day in 2011) of $53.78 and reflect the vesting of the following number of restricted units: Mr. Shaw, 2,367; Mr. Cunningham, 3,181; and Ms. McWatters, 1,141. While Mr. Clifton will remain eligible to vest in 30,731 performance units upon his death, disability or retirement after age 62, none of those performance units will automatically vest upon the occurrence of such events.

COMPENSATION PRACTICES AS THEY RELATE TO RISK MANAGEMENT

Although a significant portion of the compensation provided to the Named Executive Officers is performance-based, we believe our compensation programs do not encourage excessive and unnecessary risk taking by executive officers (or other employees) because these programs are designed to encourage employees to remain focused on both our short- and long-term operational and financial goals.

While annual cash-based incentive bonus awards play an appropriate role in the executive compensation program, the Committee believes that payment should be determined based on an evaluation of HEP performance on a wide variety of measures, as compared to our past performance and the performance of our peers, which mitigates excessive risk-taking that could produce unsustainable gains in one area of performance at the expense of our overall long-term interests. In addition, we set performance goals that we believe are reasonable in light of our past performance and market conditions. For Named Executive Officers performing a majority of their services to HEP, an appropriate part of total compensation is fixed, while another portion is variable and linked to performance. A portion of the variable compensation we provide is comprised of long-term incentives. A portion of the long-term incentives we provide is in the form of restricted units subject to time-based vesting conditions, which retains value even in a depressed market, so executives are less likely to take unreasonable risks. With respect to our performance-based equity incentives, assuming achievement of at least a minimum level of performance, payouts result in some compensation at levels below full target achievement, in lieu of an all or nothing approach. Further, our unit ownership guidelines require certain of our executives to hold certain levels of units (in addition to unvested and unsettled equity-based awards), which aligns an appropriate portion of their personal wealth to our long-term performance and the interests of our unitholders.

GUIDELINES FOR UNIT OWNERSHIP FOR OUTSIDE DIRECTORS

Pursuant to the unit ownership guidelines approved by the Board in 2009, each outside director is expected to maintain an ownership level of Common Units with a market value of $125,000. To the extent an outside director does not meet these guidelines, he will be expected to retain 25% of the units received upon settlement of restricted units awarded to him, until such time as the unit ownership requirement is met. Units owned from any source count toward meeting the guideline, but units relating to unvested restricted units do not count. As of December 31, 2011, each of our outside directors was in compliance with the unit ownership guidelines.

GUIDELINES FOR UNIT OWNERSHIP FOR EXECUTIVES

Pursuant to the unit ownership guidelines approved by the Board in 2009, each Named Executive Officer specified below is expected to retain twenty-five percent of the after-tax units received from restricted unit and performance unit awards made in 2006 and subsequent years until his ownership equals the following levels:

Executive	Value of Units
Matthew P. Clifton	$ 500,000
Bruce R. Shaw	$ 250,000

To the extent each of the Named Executive Officers listed above does not meet these guidelines, he will be expected to retain 25% of the after-tax units received upon settlement of restricted unit and performance unit awards.

Units owned from any source count toward meeting the guideline, but units relating to unvested restricted units and/or performance units do not count. As of December 31, 2011, each of the Named Executive Officers listed above was in compliance with the unit ownership guidelines.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

The following table sets forth as of February 15, 2012 the beneficial ownership of common units of HEP held by:

- each person known to us to be a beneficial owner of 5% or more of the common units;
- directors of HLS, the general partner of our general partner;
- each named executive officer of HLS;
- and by all directors and executive officers of HLS as a group.

The percentage of common units noted below is based on 27,361,124 common units outstanding as of February 15, 2012. Unless otherwise indicated, the address for each unit holder shall be c/o Holly Energy Partners, L.P., 2828 N. Harwood, Suite 1300, Dallas, Texas 75201-1507.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned
HollyFrontier Corporation (1)	11,097,615	40.6%
Tortoise Capital Advisors, L.L.C. (2)	2,747,667	10.0%
The Goldman Sachs Group, Inc. (3)	1,494,357	5.5%
SteelPath Fund Advisors, LLC (4)	1,520,145	5.6%
Matthew P. Clifton	100,127	*
Doug S. Aron(5)	420	*
Bruce R. Shaw (6)	10,079	*
David G. Blair (7)	22,187	*
Mark T. Cunningham (8)	10,013	*
Denise C. McWatters (9)	4,708	*
Michael C. Jennings	2,000	*
P. Dean Ridenour (10)	31,944	*
Charles M. Darling, IV (11)	20,960	*
William J. Gray (12)	8,159	*
Jerry W. Pinkerton (13)	9,760	*
William P. Stengel (14)	7,652	*
James G. Townsend	6,752	*
All directors and executive officers as group (12 persons) (6, 8-15)	218,038	*

* Less than 1%

(1) HollyFrontier Corporation directly holds 72,503 common units over which it has sole voting and dispositive power and 11,025,112 common units over which it has shared voting and dispositive power. The 11,025,112 common units over which HollyFrontier Corporation has shared voting and dispositive power are held as follows: Holly Logistics Limited LLC directly holds 10,807,615 common units; Navajo Pipeline Co., L.P. directly holds 127,440 common units; and other wholly-owned subsidiaries of Holly Corporation directly own 90,057 common units. HollyFrontier Corporation is the ultimate parent company of each such entity and may, therefore, be deemed to beneficially own the units held by each such entity. HollyFrontier Corporation files information with or furnishes information to, the Securities and Exchange Commission pursuant to the information requirements of the Exchange Act. The percentage of total units beneficially owned includes a 2% general partner interest held by HEP Logistics Holdings, L.P. which is HEP s general partner and an indirect wholly-owned subsidiary of HollyFrontier Corporation. The address of

HollyFrontier Corporation is 2828 N. Harwood, Suite 1300, Dallas, Texas 75201-1507.

(2) Tortoise Capital Advisors, L.L.C. filed with the SEC a Schedule 13G/A, dated February 10, 2012. Based on this Schedule 13G/A, Tortoise Capital Advisors, L.L.C. has sole voting power and sole dispositive power with respect to zero units, shared voting power with respect to 2,592,956 units and shared dispositive power with respect to 2,747,667 units. The address of Tortoise Capital Advisors, L.L.C. is 11550 Ash St., Suite 300, Leawood, KS 66211.

(3) The Goldman Sachs Group, Inc. filed with the SEC a Schedule 13G/A, dated February 8, 2012. Based on this Schedule 13G/A, the Goldman Sachs Group, Inc. has sole voting power, sole dispositive power and shared voting power with respect to zero units and shared dispositive power with respect to 1,494,357 units. The address of The Goldman Sachs Group, Inc. is 200 West Street, New York, NY 10282.

(4) SteelPath Fund Advisors, LLC filed with the SEC a Schedule 13G, dated February 13, 2012. Based on this Schedule 13G, SteelPath Fund Advisors, LLC has shared voting power and shared dispositive power with respect to 1,520,145 units. The address of SteelPath Fund Advisors, LLC is 2100 McKinney Ave., Suite 1401, Dallas, TX 75201.

(5) Reflects units beneficially owned by Mr. Aron as of December 30, 2011, based on a Form 3 filed for Mr. Aron on July 11, 2011. Includes 210 shares held by Mr. Aron as custodian for his son in an account under the Uniform Transfer to Minors Act and 210 shares held by Mr. Aron as custodian for his daughter in an account under the Uniform Transfer to Minors Act. Mr. Aron disclaims beneficial ownership of these shares.

(6) Includes 1,782 restricted units granted to Mr. Shaw for which Mr. Shaw has voting but not dispositive power.

(7) Reflects the number of units beneficially owned on July 1, 2011, based on a Form 4 filed for Mr. Blair on July 6, 2011, following his departure from HLS. In addition, it reflects the forfeiture of 3,144 restricted units, which Mr. Blair agreed to forfeit in connection with his departure from HLS.

(8) Includes 3,186 restricted units granted to Mr. Cunningham for which Mr. Cunningham has voting but not dispositive power.

(9) Includes 854 restricted units granted to Ms. McWatters for which Ms. McWatters has voting but not dispositive power and 2,000 common units owned by Ms. McWatters spouse for which Ms. McWatters shares voting and disposition power. Ms. McWatters disclaims beneficial ownership as to the common units owned by her spouse.

(10) Includes 1,374 restricted units granted to Mr. Ridenour for which Mr. Ridenour has voting but not dispositive power.

(11) Includes 1,374 restricted units granted to Mr. Darling for which Mr. Darling has voting but not dispositive power and 11,200 common units owned by DQ Holdings, L.L.C. Mr. Darling is an owner and general manager of DQ Holdings, L.L.C. and, as such, has shared voting and dispositive power with respect to the 11,200 common units owned by DQ Holdings, L.L.C. Mr. Darling disclaims beneficial ownership as to the common units held by DQ Holdings, L.L.C. except to the extent of his pecuniary interest therein.

(12) Includes 1,374 restricted units granted to Mr. Gray for which Mr. Gray has voting but not dispositive power.

(13) Includes 1,374 restricted units granted to Mr. Pinkerton for which Mr. Pinkerton has voting but not dispositive power.

(14) Includes 1,374 restricted units granted to Mr. Stengel for which Mr. Stengel has voting but not dispositive power and 500 common units owned by Mr. Stengel s spouse for which Mr. Stengel shares voting and disposition power. Mr. Stengel disclaims beneficial ownership as to the common units owned by his spouse.

(15) Includes 5,884 common units held by Mr. Scott C. Surplus, which includes 854 restricted units granted to Mr. Surplus for which Mr. Surplus has voting but not dispositive power.

Equity Compensation Plan Table

The following table summarizes information about our equity compensation plans as of December 31, 2011:

	Number of Securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected)
Equity compensation plans approved by security holders			
Equity compensation plans not approved by security holders	64,487[1]		60,604
Total			60,604

[1] Represents units subject to performance units granted to Mr. Clifton under the Long-Term Incentive Plan in 2009, 2010 and 2011 assuming a maximum payout level of 150% at the time of vesting. If the performance units granted to Mr. Clifton in 2009, 2010 and 2011 are paid at the threshold payout level of 100%, 42,991 units would be issued upon the vesting of such performance units.

For more information about our Long-Term Incentive Plan, which did not require approval by our limited partners, refer to Item 11, Executive and Director Compensation - Long-Term Incentive Plans .

Item 13. Certain Relationships, Related Transactions and Director Independence

Our general partner and its affiliates own 11,097,615 of our common units representing a 40% limited partner interest in us. In addition, the general partner owns a 2% general partner interest in us. Transactions with the general partner are discussed below.

Transactions with our general partner are discussed later in this section.

DISTRIBUTIONS AND PAYMENTS TO THE GENERAL PARTNER AND ITS AFFILIATES

The following table summarizes the distributions and payments to be made by us to our general partner and its affiliates in connection with the ongoing operation and liquidation of HEP. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm s-length negotiations.

Operational stage

Distributions of available cash to our general partner and its affiliates	We generally make cash distributions 98% to the unitholders, including our general partner and its affiliates as the holders of an aggregate of 11,097,615 of the common units and 2% to the general partner. In addition, if distributions exceed the minimum quarterly distribution and other higher target levels, our general partner is entitled to increasing percentages of the distributions, up to 50% of the distributions above the highest target level.

Payments to our general partner and its affiliates	We pay HFC or its affiliates an administrative fee, currently $2.3 million per year, for the provision of various general and administrative services for our benefit. The administrative fee 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. In addition, the general partner is entitled to reimbursement for all expenses it incurs on our behalf, including other general and administrative expenses. These reimbursable expenses include the salaries and the cost of employee benefits of employees of HLS who provide services to us. Please read Omnibus Agreement below. Our general partner determines the amount of these expenses.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.

Liquidation stage

Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

OMNIBUS AGREEMENT

Our Omnibus Agreement with HFC and our general partner that addresses the following matters:

- our obligation to pay HFC an annual administrative fee, currently in the amount of $2.3 million, for the provision by HFC of certain general and administrative services;
- HFC s and its affiliates agreement not to compete with us under certain circumstances and our right to notice of, and right of first offer to purchase, certain logistics assets constructed by HFC and acquired as part of an acquisition by HFC of refining assets;
- an indemnity by HFC for certain potential environmental liabilities;
- our obligation to indemnify HFC for environmental liabilities related to our assets existing on the date of our initial public offering to the extent HFC is not required to indemnify us; and
- HFC s right of first refusal to purchase our assets that serve HFC s refineries.

Payment of general and administrative services fee

Under the Omnibus Agreement we pay HFC an annual administrative fee, currently in the amount of $2.3 million, for the provision of various general and administrative services for our benefit. Our general partner may agree to further increases in connection with expansions of our operations through the acquisition or construction of new assets or businesses.

The $2.3 million fee includes expenses incurred by HFC and its affiliates to perform centralized corporate functions, such as legal, accounting, treasury, information technology and other corporate services, including the administration of employee benefit plans. The fee does not include salaries of pipeline and terminal personnel or other employees of HLS or the cost of their employee benefits, such as 401(k), pension, and health insurance benefits, which are separately charged to us by HFC. We also reimburse HFC and its affiliates for direct general and administrative expenses they incur on our behalf.

Noncompetition

HFC and its affiliates have agreed, for so long as HFC controls our general partner, not to engage in, whether by acquisition or otherwise, the business of operating crude oil pipelines or terminals, refined product pipelines or terminals, intermediate pipelines or terminals, truck racks or crude oil gathering systems in the continental United States. This restriction will not apply to:

- any business operated by HFC or any of its affiliates at the time of the closing of our initial public offering;
- any business conducted by HFC with the approval of our general partner;
- any business or asset that HFC or any of its affiliates 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 affiliates 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.

The limitations on the ability of HFC and its affiliates to compete with us will terminate if HFC ceases to control our general partner.

Indemnification

Under the Omnibus Agreement and certain transportation agreements with HFC, HFC has agreed to indemnify us, subject to certain limitations, for environmental noncompliance and remediation liabilities associated with assets transferred to us from HFC and occurring or existing prior to the date of such transfers. The Omnibus Agreement provides environmental indemnification with respect to certain transferred assets of up to $15 million through 2021, plus additional indemnification of $2.5 million through 2015 and up to $7.5 million through 2023. HFC s indemnification obligations under the Omnibus Agreement do not apply to (i) the Tulsa west loading racks acquired in August 2009, (ii) the 16-inch intermediate pipeline acquired in June 2009, (iii) the Roadrunner Pipeline, (iv) the Beeson Pipeline, (v) the logistics and storage assets acquired from Sinclair in December 2009, or (vi) the Tulsa east storage tanks and loading racks acquired in March 2010. For the Tulsa loading racks acquired from HFC in August 2009 and the Tulsa logistics and storage assets acquired from Sinclair in December 2009, HFC agreed to indemnify us for environmental liabilities arising from our pre-ownership operations of these assets. Additionally, HFC agreed to indemnify us for any liabilities arising from its operation of our loading racks located at HFC s Tulsa refinery west facility.

We have indemnified HFC and its affiliates against environmental liabilities related to our assets that occur after the date we acquired such asset.

Right of first refusal to purchase our assets

The Omnibus Agreement also contains the terms under which HFC has a right of first refusal to purchase our assets that serve its refineries. Before we enter into any contract to sell pipeline and terminal assets serving HFC s refineries, we must give written notice of the terms of such proposed sale to HFC. The notice must set forth the name of the third-party purchaser, the assets to be sold, the purchase price, all details of the payment terms and all other terms and conditions of the offer. To the extent the third-party offer consists of consideration other than cash (or in addition to cash), the purchase price shall be deemed equal to the amount of any such cash plus the fair market value of such non-cash consideration, determined as set forth in the Omnibus Agreement. HFC will then have the sole and exclusive option for a period of thirty days following receipt of the notice, to purchase the subject assets on the terms specified in the notice.

PIPELINE AND TERMINAL, TANKAGE AND THROUGHPUT AGREEMENTS

We serve HFC s refineries under long-term pipeline and terminal, tankage and throughput agreements expiring in 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 the Federal Energy Regulatory Commission (FERC) index. As of December 31, 2011, these agreements with HFC will result in minimum annualized payments to us of $192 million.

HFC s obligations under these agreements will not terminate if HFC and its affiliates no longer own the general partner. These agreements may be assigned by HFC only with the consent of our conflicts committee.

SUMMARY OF TRANSACTIONS WITH HFC

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 3,807,615 million of our common units. Indebtedness under the Promissory Notes bears interest at a rate equal to one-month LIBOR plus an applicable rate, currently 3.50%. To the extent any principal amount of the Promissory Notes is due and outstanding, the applicable rate shall increase by 0.25% on November 1, 2013 and on each February 1, May 1, August 1 and November 1 thereafter until the Promissory Notes have been paid in full. Interest is due and payable semi-annually on May 1 and November 1 of each year. However in the event that such payment is not permitted pursuant to the terms of the Amended Credit Agreement, such payment shall be deferred, and interest accrued shall be added to the principal balance outstanding of the Promissory Notes. As of February 16, 2012, $72.9 million is outstanding under the Promissory Notes and we have made no interest payments.

Tulsa East / Lovington Storage Asset Transaction - On March 31, 2010, we acquired from HFC certain storage assets for $93 million located at HFC s Tulsa refinery east facility and an asphalt loading rack facility located at HFC s Navajo refinery Lovington facility.

Roadrunner / Beeson Pipelines Transaction - On December 1, 2009, we acquired from HFC two newly constructed pipelines for $46.5 million.

Tulsa West Loading Racks Transaction - On August 1, 2009, we acquired from HFC certain truck and rail loading/unloading facilities located at HFC s Tulsa refinery west facility for $17.5 million.

Lovington-Artesia Pipeline Transaction - On June 1, 2009, we acquired a newly constructed 16-inch intermediate pipeline from HFC for $34.2 million.

*See 2011 Acquisition, 2010 Acquisitio*ns and 2009 Acquisitions under Item 1, Business of this Annual Report on Form 10-K for additional information on these acquisitions from HFC.

Revenues received from HFC were $167.6 million, $146.4 million and $101.4 million for the years ended December 31, 2011, 2010 and 2009, respectively.

HFC charged general and administrative services under the Omnibus Agreement of $2.3 million for each of the years ended December 31, 2011, 2010 and 2009, respectively.

We reimbursed HFC for costs of employees supporting our operations of $21.4 million, $18.6 million and $17 million for the years ended December 31, 2011, 2010 and 2009, respectively.

HFC reimbursed us $11.9 million, $3.7 million and $1.7 million for certain costs paid on their behalf for the years ended December 31, 2011, 2010 and 2009, respectively.

We paid HFC a $2.5 million finder s fee in connection the acquisition of our 25% joint venture interest in the SLC Pipeline in the first quarter of 2009.

We distributed $40.6 million, $35.9 million and $29.5 million for the years ended December 31, 2011, 2010 and 2009, respectively, to HFC as regular distributions on its common units, subordinated units and general partner interest, including general partner incentive distributions.

REVIEW, APPROVAL OR RATIFICATION OF TRANSACTIONS WITH RELATED PERSONS

The disclosure, review and approval of any transactions with related persons is governed by our Code of Business Conduct and Ethics, which provides guidelines for disclosure, review and approval of any transaction that creates a conflict of interest between us and our employees, officers or directors and members of their immediate family. Conflict of interest transactions may be authorized if they are found to be in the best interest of the Partnership based on all relevant facts. Pursuant to the Code of Business Conduct and Ethics, conflicts of interest are to be disclosed to and reviewed by a superior employee to the related person who does not have a conflict of interest, and additionally, if more than trivial size, by the superior of the reviewing person. Conflicts of interest involving directors or senior executive officers are reviewed by the full Board of Directors or by a committee of the Board of Directors on which the related person does not serve. Related party transactions required to be disclosed in our SEC reports are reported through our disclosure controls and procedures.

There are no transactions disclosed in this Item 13 entered into since January 1, 2011 that were not required to be reviewed, ratified or approved pursuant to our Code of Business Conduct and Ethics or with respect to which our policies and procedures with respect to conflicts of interest were not followed.

See Item 10 for a discussion of Director Independence.

Item 14. Principal Accountant Fees and Services

The audit committee of the board of directors of HLS selected Ernst & Young LLP, Independent Registered Public Accounting Firm, to audit the books, records and accounts of the HEP for the 2011 calendar year.

Fees paid to Ernst & Young LLP for 2011 and 2010 are as follows:

	2011	**2010**
Audit Fees (1)	$ 662,000	$ 551,000
Audit Related Fees		
Tax Fees	176,000	204,000
All Other Fees		
Total	$ 838,000	$ 755,000

(1) Represents fees for professional services provided in connection with the audit of our annual financial statements and internal controls over financial reporting, review of our quarterly financial statements, and procedures performed as part of our securities filings.

The audit committee of our general partner s board of directors has adopted an audit committee charter, which is available on our website at www.hollyenergy.com. The charter requires the audit committee to approve in advance all audit and non-audit services to be provided by our independent registered public accounting firm. All services reported in the audit, audit-related, tax and all other fee categories above were approved by the audit committee in advance.

Part IV

Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(a) Documents filed as part of this report

(1) Index to Consolidated Financial Statements

(2) Index to Consolidated Financial Statement Schedules

All schedules are omitted since the required information is not present in or not present in amounts sufficient to require submission of the schedule, or because the information required is included in the consolidated financial statements or notes thereto.

(3) Exhibits

See Index to Exhibits on pages 133 to 142.

HOLLY ENERGY PARTNERS, L.P.

SIGNATURES

Pursuant to the requirements of the Securities and Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

HOLLY ENERGY PARTNERS, L.P.
(Registrant)

By: HEP LOGISTICS HOLDINGS, L.P.
its General Partner

By: HOLLY LOGISTIC SERVICES, L.L.C.
its General Partner

Date: February 24, 2012

/s/ Matthew P. Clifton
Matthew P. Clifton
Chairman of the Board of Directors, Chief Executive Officer and President

/s/ Bruce R, Shaw
Bruce R. Shaw
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ Scott C. Surplus
Scott C. Surplus
Vice President and Controller
(Principal Accounting Officer)

/s/ Charles M. Darling, IV
Charles M. Darling, IV
Director

/s/ William J. Gray
William J. Gray
Director

/s/ Michael C. Jennings
Michael C. Jennings
Director

/s/ Jerry W. Pinkerton
Jerry W. Pinkerton
Director

/s/ P. Dean Ridenour
P. Dean Ridenour
Director

/s/ William P. Stengel
William P. Stengel
Director

/s/ James G. Townsend

James G. Townsend
Director

Exhibit Index

Exhibit Number	Description
2.1	Purchase and Sale Agreement, dated February 25, 2008 between Holly Corporation, Navajo Pipeline Co., L.P., Navajo Refining Company, L.L.C., Woods Cross Refining Company, L.L.C., Holly Energy Partners, L.P., Holly Energy Partners - Operating, L.P., HEP Pipeline, L.L.C., and HEP Woods Cross, L.L.C. (incorporated by reference to Exhibit 2.1 of Registrant s Form 8-K Current Report dated February 27, 2008, File No. 1-32225).
2.2	Asset Sale and Purchase Agreement, dated October 19, 2009, between Holly Refining & Marketing Tulsa LLC, HEP Tulsa LLC, and Sinclair Tulsa Refining Company (incorporated by reference to Exhibit 2.1 of Registrant s Form 8-K Current Report dated October 21, 2009, File No. 1-32225).
3.1	First Amended and Restated Agreement of Limited Partnership of Holly Energy Partners, L.P. (incorporated by reference to Exhibit 3.1 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2004, File No. 1-32225).
3.2	Amendment No. 1 to the First Amended and Restated Agreement of Limited Partnership of Holly Energy Partners, L.P., dated February 28, 2005 (incorporated by reference to Exhibit 3.1 of Registrant s Form 8-K Current Report dated February 28, 2005, File No. 1-32225).
3.3	Amendment No. 2 to the First Amended and Restated Agreement of Limited Partnership of Holly Energy Partners, L.P., as amended, dated July 6, 2005 (incorporated by reference to Exhibit 3.1 of Registrant s Form 8-K Current Report dated July 6, 2005, File No. 1-32225).
3.4	Amendment No. 3 to First Amended and Restated Agreement of Limited Partnership of Holly Energy Partners, L.P., dated April 11, 2008 (incorporated by reference to Exhibit 4.1 of Registrant s Current Report on Form 8-K filed April 15, 2008, File No. 1-32225).
3.5	First Amended and Restated Agreement of Limited Partnership of Holly Energy Partners - Operating Company, L.P. (incorporated by reference to Exhibit 3.2 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2004, File No. 1-32225).
3.6	First Amended and Restated Agreement of Limited Partnership of HEP Logistics Holdings, L.P. (incorporated by reference to Exhibit 3.4 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2004, File No. 1-32225).
3.7	First Amended and Restated Limited Liability Company Agreement of Holly Logistic Services, L.L.C. (incorporated by reference to Exhibit 3.5 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2004, File No. 1-32225).
3.8	Amendment No. 1 to the First Amended and Restated Limited Liability Company Agreement of Holly Logistic Services, L.L.C., dated April 27, 2011 (incorporated by reference to Exhibit 3.1 of Registrant s Form 8-K Current Report dated May 3, 2011, File No. 1-32225).
3.9	First Amended and Restated Limited Liability Company Agreement of HEP Logistics GP, L.L.C. (incorporated by reference to Exhibit 3.6 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2004, File No. 1-32225).
4.1	Indenture, dated February 28, 2005, among the Issuers, the Guarantors and the Trustee (incorporated by reference to Exhibit 4.1 of Registrant s Form 8-K Current Report dated February 28, 2005, File No. 1-32225).

4.2	Form of 6.25% Senior Note Due 2015 (included as Exhibit A to the Indenture filed as Exhibit 4.1 hereto) (incorporated by reference to Exhibit 4.2 of Registrant s Form 8-K Current Report dated February 28, 2005, File No. 1-32225).
4.3	Form of Notation of Guarantee (included as Exhibit E to the Indenture filed as Exhibit 4.1 hereto) (incorporated by reference to Exhibit 4.3 of Registrant s Form 8-K Current Report dated February 28, 2005, File No. 1-32225).
4.4	First Supplemental Indenture, dated March 10, 2005, among HEP Fin-Tex/Trust-River, L.P., Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors, and U.S. Bank National Association (incorporated by reference to Exhibit 4.5 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended March 31, 2005, File No. 1-32225).
4.5	Second Supplemental Indenture, dated April 27, 2005, among Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors, and U.S. Bank National Association (incorporated by reference to Exhibit 4.6 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended March 31, 2005, File No. 1-32225).
4.6	Third Supplemental Indenture, dated as of June 11, 2009, among Lovington-Artesia, L.L.C., Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors, and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2009, File No. 1-32225).
4.7	Fourth Supplemental Indenture, dated as of June 29, 2009, among HEP SLC, LLC, Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors, and U.S. Bank National Association (incorporated by reference to Exhibit 4.2 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2009, File No. 1-32225).
4.8	Fifth Supplemental Indenture, dated as of July 13, 2009, among HEP Tulsa LLC, Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors, and U.S. Bank National Association (incorporated by reference to Exhibit 4.3 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2009, File No. 1-32225).
4.9	Sixth Supplemental Indenture, dated as of December 15, 2009, among Roadrunner Pipeline, L.L.C., Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors, and U.S. Bank National Association (incorporated by reference to Exhibit 4.9 of Registrant s Annual Report on Form 10-K for its fiscal year ended December 31, 2009, File No. 1-32225).
4.10	Seventh Supplemental Indenture, dated as of April 14, 2010, among Holly Energy Storage- Tulsa LLC, Holly Energy Storage-Lovington LLC, Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors, and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2010, File No. 1-32225).
4.11	Eighth Supplemental Indenture, dated as of June 4, 2010, among HEP Operations LLC, Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors, and U.S. Bank National Association (incorporated by reference to Exhibit 4.2 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2010, File No. 1-32225).
4.12*	Ninth Supplemental Indenture, dated as of December 29, 2011, among Cheyenne Logistics LLC, El Dorado Logistics LLC, Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors, and U.S. Bank National Association.

4.13	Indenture, dated March 10, 2010, among Holly Energy Partners, L.P., Holly Energy Finance Corp. and each of the guarantors party thereto and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 of Registrant s Form 8-K Current Report dated March 11, 2010, File No. 1-32225).
4.14	First Supplemental Indenture, dated as of April 14, 2010, among Holly Energy Storage- Tulsa LLC, Holly Energy Storage-Lovington LLC, Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors, and U.S. Bank National Association (incorporated by reference to Exhibit 4.3 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2010, File No. 1-32225).
4.15	Second Supplemental Indenture, dated as of June 4, 2010, among HEP Operations LLC, Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors, and U.S. Bank National Association (incorporated by reference to Exhibit 4.4 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2010, File No. 1-32225).
4.16*	Third Supplemental Indenture, dated December 29, 2011, among Cheyenne Logistics LLC, El Dorado Logistics LLC, Holly Energy Partners, L.P., Holly Energy Finance Corp., the other Guarantors, and U.S. Bank National Association.
10.1	Option Agreement, dated January 31, 2008, by and among Holly Corporation, Holly UNEV Pipeline Company, Navajo Pipeline Co., L.P., Holly Logistic Services, L.L.C., HEP Logistics Holdings, L.P., Holly Energy Partners, L.P., HEP Logistics GP, L.L.C. and Holly Energy Partners - Operating, L.P. (incorporated by reference to Exhibit 10.1 of Registrant s Form 8-K Current Report dated February 5, 2008, File No. 1-32225).
10.2	First Amendment to Option Agreement, dated February 11, 2010, by and among Holly Corporation, Holly UNEV Pipeline Company, Navajo Pipeline Co., L.P., Holly Logistic Services, L.L.C., HEP Logistics Holdings, L.P., Holly Energy Partners, L.P., HEP Logistics GP, L.L.C. and Holly Energy Partners - Operating, L.P. (incorporated by reference to Exhibit 10.2 of Registrant s Annual Report on Form 10-K for its fiscal year ended December 31, 2010, File No. 1-32225)
10.3	Mortgage, Line of Credit Mortgage and Deed of Trust, dated February 29, 2008, by HEP Pipeline, L.L.C. for the benefit of Holly Corporation (incorporated by reference to Exhibit 10.2 of Registrant s Form 8-K Current Report dated March 6, 2008, File No. 1-32225).
10.4	Mortgage, Line of Credit Mortgage and Deed of Trust, dated February 29, 2008, by HEP Pipeline, L.L.C. for the benefit of Holly Corporation (incorporated by reference to Exhibit 10.3 of Registrant s Form 8-K Current Report dated March 6, 2008, File No. 1-32225).
10.5	Mortgage, Line of Credit Mortgage and Deed of Trust, dated February 29, 2008, by HEP Pipeline, L.L.C. for the benefit of Holly Corporation (incorporated by reference to Exhibit 10.4 of Registrant s Form 8-K Current Report dated March 6, 2008, File No. 1-32225).
10.6	Mortgage and Deed of Trust, dated February 29, 2008, by HEP Pipeline, L.L.C. for the benefit of Holly Corporation (incorporated by reference to Exhibit 10.5 of Registrant s Form 8-K Current Report dated March 6, 2008, File No. 1-32225).
10.7	Mortgage and Deed of Trust, dated February 29, 2008, by HEP Pipeline, L.L.C. for the benefit of Holly Corporation (incorporated by reference to Exhibit 10.6 of Registrant s Form 8-K Current Report dated March 6, 2008, File No. 1-32225).
10.8	Fee and Leasehold Deed of Trust, dated February 29, 2008, by HEP Woods Cross, L.L.C. for the benefit of Holly Corporation (incorporated by reference to Exhibit 10.7 of Registrant s Form 8-K Current Report dated March 6, 2008, File No. 1-32225).

10.9	Amended and Restated Credit Agreement, dated August 27, 2007, between Holly Energy Partners - Operating, L.P., Union Bank of California, N.A., as administrative agent, issuing bank and sole lead arranger, Bank of America, N.A., as syndication agent, Guaranty Bank, as documentation agent and certain other lenders (incorporated by reference to Exhibit 10.1 of Registrant s Form 8-K Current Report dated October 31, 2007, File No. 1-32225).
10.10	Agreement and Amendment No. 1 to Amended and Restated Credit Agreement, dated February 25, 2008, between Holly Energy Partners - Operating, L.P., Union Bank of California, N.A., as administrative agent, issuing bank and sole lead arranger and certain other lenders (incorporated by reference to Exhibit 10.1 of Registrant s Form 8-K Current Report dated February 27, 2008, File No. 1-32225).
10.11	Amendment No. 2 to Amended and Restated Credit Agreement, dated September 8, 2008, between Holly Energy Partners Operating, L.P., certain of its subsidiaries acting as guarantors, Union Bank of California, N.A., as administrative agent, issuing bank and sole lead arranger and certain other lenders (incorporated by reference to Exhibit 10.1 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended September 30, 2008, File No. 1-32225).
10.12	Pipelines and Terminals Agreement, dated February 28, 2005, among the Partnership and Alon USA, LP2005 (incorporated by reference to Exhibit 10.1 of Registrant s Form 8-K Current Report dated February 28, 2005, File No. 1-32225).
10.13	First Amendment of Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and Alon USA, LP, dated September 1, 2008 (incorporated by reference to Exhibit 10.4 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2011, File No. 001-32225).
10.14	Second Amendment to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and Alon USA, LP, dated March 1, 2011 (incorporated by reference to Exhibit 10.5 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2011, File No. 001-32225).
10.15	Third Amendment to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and Alon USA, LP, dated June 6, 2011 (incorporated by reference to Exhibit 10.6 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2011, File No. 001-32225).
10.16	First Letter Agreement with respect to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and Alon USA, LP, dated January 25, 2005 (incorporated by reference to Exhibit 10.1 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2011, File No. 001-32225).
10.17	Second Letter Agreement with respect to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and Alon USA, LP, dated June 29, 2007 (incorporated by reference to Exhibit 10.2 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2011, File No. 001-32225).
10.18	Third Letter Agreement with respect to Pipelines and Terminals Agreement between Holly Energy Partners, L.P. and Alon USA, LP, dated April 1, 2011 (incorporated by reference to Exhibit 10.3 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2011, File No. 001-32225).
10.19	Corrected Version Dated October 10, 2007 of Amendment and Supplement to Pipeline Lease Agreement effective as of August 31, 2007 between HEP Pipeline Assets, Limited Partnership and Alon USA, L.P. (incorporated by reference to Exhibit 10.1 of Registrant s Form 8-K Current Report dated October 16, 2007, File No. 1-32225).

10.20	LLC Interest Purchase Agreement, dated as of June 1, 2009, among Holly Corporation, Navajo Pipeline Co., L.P., and Holly Energy Partners Operating, L.P. (incorporated by reference to Exhibit 10.1 of Registrant s Form 8-K Current Report dated June 5, 2009, File No. 1-32225).
10.21	Amended and Restated Intermediate Pipelines Agreement, dated as of June 1, 2009, among Holly Corporation, Navajo Refining Company, L.L.C., Holly Energy Partners, L.P., Holly Energy Partners Operating, L.P., Holly Logistic Services, L.L.C., and HEP Logistics GP, L.L.C. (incorporated by reference to Exhibit 10.2 of Registrant s Form 8-K Current Report dated June 5, 2009, File No. 1-32225).
10.22	Amendment to Amended and Restated Intermediate Pipelines Agreement, dated as of December 9, 2010, among Navajo Refining Company, L.L.C., Holly Energy Partners, L.P., Holly Energy Partners Operating, L.P., HEP Pipeline, L.L.C., Lovington-Artesia, L.L.C., HEP Logistics Holdings, L.P., Holly Logistic Services, L.L.C., and HEP Logistics GP, L.L.C. (incorporated by reference to Exhibit 10.23 of Registrant s Annual Report on Form 10-K for its fiscal year ended December 31, 2010, File No. 1-3225).
10.23	Assignment and Assumption Agreement (Amended and Restated Intermediate Pipelines Agreement), effective as of January 1, 2011, between Navajo Refining Company, L.L.C. and Holly Refining & Marketing Company LLC. (incorporated by reference to Exhibit 10.24 of Registrant s Annual Report on Form 10-K for its fiscal year ended December 31, 2010, File No. 1-3225).
10.24	Mortgage, Line of Credit Mortgage and Deed of Trust, dated as of June 1, 2009, by Lovington-Artesia, L.L.C. for the benefit of Holly Corporation (incorporated by reference to Exhibit 10.4 of Registrant s Form 8-K Current Report dated June 5, 2009, File No. 1-32225).
10.25	Asset Purchase Agreement, dated as of August 1, 2009, between Holly Refining & Marketing Tulsa LLC and HEP Tulsa LLC (incorporated by reference to Exhibit 10.1 of Registrant s Form 8-K Current Report dated August 6, 2009, File No. 1-32225).
10.26	Tulsa Equipment and Throughput Agreement, dated August 1, 2009, between Holly Refining & Marketing Tulsa LLC and HEP Tulsa LLC (incorporated by reference to Exhibit 10.3 of Registrant s Form 8-K Current Report dated August 6, 2009, File No. 1-32225).
10.27	Amendment to Tulsa Equipment and Throughput Agreement, dated as of December 9, 2010, among Holly Refining & Marketing Tulsa LLC and HEP Tulsa LLC. (incorporated by reference to Exhibit 28 of Registrant s Annual Report on Form 10-K for its fiscal year ended December 31, 2010, File No. 1-3225).
10.28	Assignment and Assumption Agreement (Tulsa Equipment and Throughput Agreement), effective as of January 1, 2011, between Holly Refining & Marketing Tulsa, LLC and Holly Refining & Marketing Company LLC. (incorporated by reference to Exhibit 29 of Registrant s Annual Report on Form 10-K for its fiscal year ended December 31, 2010, File No. 1-3225).
10.29	Tulsa Purchase Option Agreement, dated August 1, 2009, between Holly Refining & Marketing Tulsa LLC and HEP Tulsa LLC (incorporated by reference to Exhibit 10.4 of Registrant s Form 8-K Current Report dated August 6, 2009, File No. 1-32225).
10.30	LLC Interest Purchase Agreement, dated as of December 1, 2009, among Holly Corporation, Navajo Pipeline Co., L.P., and Holly Energy Partners Operating, L.P. (incorporated by reference to Exhibit 10.1 of Registrant s Form 8-K Current Report dated December 7, 2009, File No. 1-32225).
10.31	Asset Purchase Agreement, dated as of December 1, 2009, between Holly Corporation, Navajo Pipeline Co., L.P. and HEP Pipeline, L.L.C. (incorporated by reference to Exhibit 10.2 of Registrant s Form 8-K Current Report dated December 7, 2009, File No. 1-32225).

10.32	Pipeline Throughput Agreement, dated as of December 1, 2009, between Navajo Refining Company, L.L.C. and Holly Energy Partners Operating, L.P. (incorporated by reference to Exhibit 10.4 of Registrant s Form 8-K Current Report dated December 7, 2009, File No. 1-32225).
10.33	Assignment and Assumption Agreement (Pipeline Throughput Agreement (Roadrunner)), effective as of January 1, 2011, between Navajo Refining Company, L.L.C. and Holly Refining & Marketing Company LLC. (incorporated by reference to Exhibit 34 of Registrant s Annual Report on Form 10-K for its fiscal year ended December 31, 2010, File No. 1-3225).
10.34	Form of Mortgage, Line of Credit Mortgage and Deed of Trust, to be entered into by HEP Pipeline L.L.C. and Holly Energy Partners, L.P. for the benefit of Holly Corporation (incorporated by reference to Exhibit 10.5 of Registrant s Form 8-K Current Report dated December 7, 2009, File No. 1-32225).
10.35	Form of Mortgage and Deed of Trust, to be entered into by Roadrunner Pipeline, L.L.C for the benefit of Holly Corporation (incorporated by reference to Exhibit 10.6 of Registrant s Form 8-K Current Report dated December 7, 2009, File No. 1-32225).
10.36	Form of Mortgage, Line of Credit Mortgage and Deed of Trust, to be entered into by Roadrunner Pipeline, L.L.C. for the benefit of Holly Corporation (incorporated by reference to Exhibit 10.7 of Registrant s Form 8-K Current Report dated December 7, 2009, File No. 1-32225).
10.37	Amended and Restated Crude Pipelines and Tankage Agreement, entered into on December 1, 2009, to be effective as of January 1, 2009, among Navajo Refining Company, L.L.C., Holly Refining & Marketing Company Woods Cross, Holly Refining & Marketing Company, Holly Energy Partners Operating, L.P., HEP Pipeline, LLC, and HEP Woods Cross, L.L.C. (incorporated by reference to Exhibit 10.8 of Registrant s Form 8-K Current Report dated December 7, 2009, File No. 1-32225).
10.38	Letter Agreement, dated October 14, 2011, regarding the Amended and Restated Crude Pipelines and Tankage Agreement, dated December 1, 2009 (incorporated by reference to Exhibit 10.3 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended September 30, 2011, File No. 001-32225).
10.39	Amended and Restated Refined Product Pipelines and Terminals Agreement, entered into on December 1, 2009, to be effective as of January 1, 2009, among Navajo Refining Company, L.L.C., Holly Refining & Marketing Company Woods Cross, Holly Refining & Marketing Company, Holly Energy Partners Operating, L.P., HEP Pipeline, LLC, HEP Refining Assets, L.P., HEP Refining, L.L.C., HEP Mountain Home, L.L.C., and HEP Woods Cross, L.L.C. (incorporated by reference to Exhibit 10.9 of Registrant s Form 8-K Current Report dated December 7, 2009, File No. 1-32225).
10.40	Assignment and Assumption Agreement (Amended and Restated Refined Product Pipelines and Terminals Agreement), effective as of January 1, 2011, among Navajo Refining Company, L.L.C., Holly Refining & Marketing-Woods Cross and Holly Refining & Marketing Company LLC. (incorporated by reference to Exhibit 40 of Registrant s Annual Report on Form 10-K for its fiscal year ended December 31, 2010, File No. 1-3225).
10.41	Indemnification Proceeds and Payments Allocation Agreement, dated as of December 1, 2009, between Holly Refining & Marketing Tulsa, LLC and HEP Tulsa LLC (incorporated by reference to Exhibit 10.2 of Registrant s Form 8-K Current Report dated December 7, 2009, File No. 1-32225).

10.42	LLC Interest Purchase Agreement, dated as of March 31, 2010, by and among Holly Corporation, Holly Refining & Marketing-Tulsa, LLC, Lea Refining Company, HEP Tulsa LLC and HEP Refining, L.L.C. (incorporated by reference to Exhibit 10.1 of Registrant s Form 8-K Current Report dated April 6, 2010, File No. 1-32225).
10.43	Second Amended and Restated Pipelines, Tankage, and Loading Rack Throughput Agreement, dated August 31, 2011 (incorporated by reference to Exhibit 10.1 of Registrant s Form 8-K Current Report dated September 1, 2011, File No. 1-32225).
10.44	Amendment to First Amended and Restated Pipelines, Tankage and Loading Rack Throughput Agreement (Tulsa East), dated as of June 11, 2010, by and between Holly Refining & Marketing-Tulsa LLC, HEP Tulsa LLC and Holly Energy Storage-Tulsa LLC (incorporated by reference to Exhibit 10.1 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2010, File No. 1-32225).
10.45	Assignment and Assumption Agreement (First Amended and Restated Pipelines, Tankage and Loading Rack Throughput Agreement (Tulsa East)), effective as of January 1, 2011, between Holly Refining & Marketing-Tulsa, LLC and Holly Refining & Marketing Company LLC. (incorporated by reference to Exhibit 45 of Registrant s Annual Report on Form 10-K for its fiscal year ended December 31, 2010, File No. 1-3225).
10.46	Loading Rack Throughput Agreement (Lovington), dated as of March 31, 2010, by and between Navajo Refining Company, L.L.C. and Holly Energy Storage-Lovington LLC (incorporated by reference to Exhibit 10.3 of Registrant s Form 8-K Current Report dated April 6, 2010, File No. 1-32225).
10.47	First Amended and Restated Lease and Access Agreement (East Tulsa), dated as of March 31, 2010, by and between Holly Refining & Marketing-Tulsa, LLC, HEP Tulsa LLC and Holly Energy Storage-Tulsa LLC (incorporated by reference to Exhibit 10.5 of Registrant s Form 8-K Current Report dated April 6, 2010, File No. 1-32225).
10.48	Pipeline Systems Operating Agreement, dated as of February 8, 2010, by and among Navajo Refining Company, L.L.C., Lea Refining Company, Woods Cross Refining Company, L.L.C., Holly Refining & Marketing Tulsa LLC and Holly Energy Partners-Operating, L.P. (incorporated by reference to Exhibit 10.1 of Registrant s Form 8-K Current Report dated February 9, 2010, File No. 1-32225).
10.49	First Amendment to Pipeline Systems Operating Agreement, dated as of March 31, 2010, by and among Navajo Refining Company, L.L.C., Lea Refining Company, Woods Cross Refining Company, L.L.C., Holly Refining & Marketing-Tulsa, LLC and Holly Energy Partners-Operating, L.P. (incorporated by reference to Exhibit 10.6 of Registrant s Form 8-K Current Report dated April 6, 2010, File No. 1-32225).
10.50	Tulsa Refinery Interconnects Term Sheet dated August 9, 2010 (incorporated by reference to Exhibit 10.1 of Registrant s Form 8-K Current Report dated August 11, 2010, File No. 1-32225).
10.51	Amendment to Tulsa Refinery Interconnects Term Sheet dated December 31, 2010 (incorporated by reference to Exhibit 10.1 of Registrant s Form 8-K Current Report dated January 6, 2011, File No. 1-32225).
10.52	Second Amendment to Tulsa Refinery Interconnects Term Sheet dated March 31, 2011 (incorporated by reference to Exhibit 10.1 of Registrant s Form 8-K Current Report dated March 31, 2011, File No. 1-32225).

10.53	LLC Interest Purchase Agreement, dated November 9, 2011, by and among HollyFrontier Corporation, Frontier Refining LLC, Frontier El Dorado Refining LLC, Holly Energy Partners Operating, L.P. and Holly Energy Partners, L.P. (incorporated by reference to Exhibit 10.1 of Registrant s Form 8-K Current Report dated November 10, 2011, File No. 001-32225).
10.54*	First Amended and Restated Tankage, Loading Rack and Crude Oil Receiving Throughput Agreement (Cheyenne), dated January 12, 2012, by and between Frontier Refining LLC and Cheyenne Logistics LLC.
10.55*	First Amended and Restated Pipeline Delivery, Tankage and Loading Rack Throughput Agreement (El Dorado), dated January 12, 2012, by and between Frontier El Dorado Refining LLC and El Dorado Logistics LLC.
10.56	Sixth Amended and Restated Omnibus Agreement, dated November 9, 2011, by and among HollyFrontier Corporation, Holly Energy Partners, L.P. and certain of their respective subsidiaries (incorporated by reference to Exhibit 10.4 of Registrant s Form 8-K Current Report dated November 10, 2011, File No. 001-32225).
10.57	Lease and Access Agreement (Cheyenne), dated November 9, 2011, by and between Frontier Refining LLC and Cheyenne Logistics LLC (incorporated by reference to Exhibit 10.5 of Registrant s Form 8-K Current Report dated November 10, 2011, File No. 001-32225).
10.58	Lease and Access Agreement (El Dorado), dated November 9, 2011, by and between Frontier El Dorado Refining LLC and El Dorado Logistics LLC (incorporated by reference to Exhibit 10.6 of Registrant s Form 8-K Current Report dated November 10, 2011, File No. 001-32225).
10.59	Form of Senior Unsecured Note in favor of Frontier Refining LLC (incorporated by reference to Exhibit 10.7 of Registrant s Form 8-K Current Report dated November 10, 2011, File No. 001-32225).
10.60	Form of Senior Unsecured Note in favor of Frontier El Dorado Refining LLC (incorporated by reference to Exhibit 10.8 of Registrant s Form 8-K Current Report dated November 10, 2011, File No. 001-32225).
10.61*	Mortgage, dated January 31, 2012, by Cheyenne Logistics LLC for the benefit of HollyFrontier Corporation.
10.62+	Holly Energy Partners, L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.9 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2004, File No. 1-32225).
10.63+	First Amendment to the Holly Energy Partners, L.P. Long-Term Incentive Plan effective January 1, 2005 (incorporated by reference to Exhibit 10.4 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended September 30, 2005, File No. 1-32225).
10.64+	Second Amendment to the Holly Energy Partners, L.P. Long-Term Incentive Plan, effective January 1, 2005 (incorporated by reference to Exhibit 10.27 of Registrant s Annual Report on Form 10-K for its fiscal year ended December 31, 2008, File No. 1-32225).
10.65+	Third Amendment to the Holly Energy Partners, L.P. Long-Term Incentive Plan effective March 3, 2009 (incorporated by reference to Exhibit 10.41 of Registrant s Annual Report on Form 10-K for its fiscal year ended December 31, 2009, File No. 1-32225).

10.66+	Holly Logistic Services, L.L.C. Annual Incentive Plan (incorporated by reference to Exhibit 10.10 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2004, File No. 1-32225).
10.67+	First Amendment to the Holly Logistic Services, L.L.C. Annual Incentive Plan effective January 1, 2005 (incorporated by reference to Exhibit 10.26 of Registrant s Annual Report on Form 10-K for its fiscal year ended December 31, 2008, File No. 1-32225).
10.68+	Form of Director Restricted Unit Agreement (incorporated by reference to Exhibit 10.1 of Registrant s Current Report on Form 8-K dated November 15, 2004, File No. 1-32225).
10.69+	Form of Employee Restricted Unit Agreement (incorporated by reference to Exhibit 10.2 of Registrant s Current Report on Form 8-K dated November 15, 2004, File No. 1-32225).
10.70+	Form of Restricted Unit Agreement (with Performance Vesting) (incorporated by reference to Exhibit 10.1 of Registrant s Form 8-K Current Report dated August 4, 2005, File No. 1-32225).
10.71+	Form of Restricted Unit Agreement (without Performance Vesting) (incorporated by reference to Exhibit 10.2 of Registrant s Form 8-K Current Report dated August 4, 2005, File No. 1-32225).
10.72+	Form of Holly Energy Partners, L.P. Indemnification Agreement to be entered into with officers and directors of Holly Logistic Services, L.L.C. (incorporated by reference to Exhibit 10.2 of Registrant s Form 8-K Current Report dated February 18, 2011, File No. 1-32225).
10.73+	Holly Energy Partners, L.P. Employee Form of Change in Control Agreement (incorporated by reference to Exhibit 10.3 of Registrant s Form 8-K Current Report dated February 20, 2008, File No. 1-32225).
10.74+	Holly Energy Partners, L.P. Change in Control Agreement Policy (incorporated by reference to Exhibit 10.3 of Registrant s Form 8-K Current Report dated February 18, 2011, File No. 1-32225).
10.75+	Form of Change in Control Agreement (incorporated by reference to Exhibit 10.4 of Registrant s Form 8-K Current Report dated February 18, 2011, File No. 1-32225).
10.76+	Form of Performance Unit Agreement (incorporated by reference to Exhibit 10.49 of Registrant s Annual Report on Form 10-K for its fiscal year ended December 31, 2009, File No. 1-32225).
10.77+	Form of Performance Unit Agreement (incorporated by reference to Exhibit 10.2 of Registrant s Quarterly Report on Form 10-Q for its quarterly period ended June 30, 2010, File No. 1-32225).
12.1*	Statement of Computation of Ratio of Earnings to Fixed Charges.
21.1*	Subsidiaries of Registrant.
23.1*	Consent of Independent Registered Public Accounting Firm.
31.1*	Certification of Chief Executive Officer under Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer under Section 302 of the Sarbanes-Oxley Act of 2002.

32.1*	Certification of Chief Executive Officer under Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Chief Financial Officer under Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.
\+ Constitutes management contracts or compensatory plans or arrangements.