HOLLY ENERGY PARTNERS LP
Form 10-K
February 16, 2010

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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, 2009
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
100 Crescent Court, Suite 1600
Dallas, Texas 75201-6915
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 o No þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes o No þ

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 þ No o

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 o No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in part III of this Form 10-K or any amendments to this Form 10-K. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer o	Accelerated filer þ	Non-accelerated filer o	Smaller reporting company o

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

The aggregate market value of common limited partner units held by non-affiliates of the registrant was approximately $357 million on June 30, 2009, 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 8, 2009 was 21,141,009.

DOCUMENTS INCORPORATED BY REFERENCE: None

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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 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, could, believe, 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 in our terminals;
- the economic viability of Holly Corporation, Alon USA, Inc. and our other customers;
- the demand for refined petroleum products in markets we serve;
- our ability to successfully purchase and integrate additional operations in the future;
- our ability to complete previously announced or contemplated acquisitions;
- the availability and cost of additional debt and equity financing;
- the possibility of reductions in production or shutdowns at refineries utilizing our pipeline and terminal facilities;
- the effects of current and future government regulations and policies;
- our operational efficiency in carrying out routine operations and capital construction projects;
- the possibility of terrorist attacks and the consequences of any such attacks;
- general economic conditions; and
- other financial, 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.

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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 oil pipelines, storage tanks, distribution terminals and loading rack facilities in west Texas, New Mexico, Utah, Arizona, Oklahoma, Idaho and Washington. We maintain our principal corporate offices at 100 Crescent Court, Suite 1600, Dallas, Texas 75201-6915. 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. Additionally 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 no any other person. Holly refers to Holly Corporation and its subsidiaries, other than HEP and its subsidiaries and other than Holly Logistic Services, L.L.C. (HLS), a subsidiary of Holly Corporation that is the general partner of the general partner of HEP and manages HEP.

We generate revenues by charging tariffs for transporting petroleum product and crude oil through our pipelines and by charging fees for terminalling refined products and other hydrocarbons, and storing and providing other services. 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. We serve Holly s refineries in New Mexico, Utah and Oklahoma under several long-term pipeline and terminal, tankage and throughput agreements. These agreements relate to the pipelines and terminals contributed to us by Holly at the time of our initial public offering in 2004 (the Holly PTA), the intermediate pipelines acquired in 2005 and in June 2009 (the Holly IPA), the crude pipelines and tankage assets acquired from Holly in 2008 (the Holly CPTA), the Tulsa loading racks acquired in August 2009 (the Holly ETA) and the Roadrunner pipeline acquired from Holly in December 2009 (the Holly RPA). Additionally, we have a pipeline, tankage and throughput agreement with Holly to provide transportation and storage services via our logistics and storage facilities that were acquired from an affiliate of Sinclair Oil Company (Sinclair) in December 2009 (the Holly PTTA). We also serve the Alon USA, Inc. (Alon) Big Spring, Texas refinery (the Big Spring Refinery) under the Alon pipelines and terminals agreement (the Alon PTA). The substantial majority of our business is devoted to providing transportation, storage and terminalling services to Holly. Holly controls our general partner and owns a 34% interest in us. We operate our business as one business segment.

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 Holly s refinery in New Mexico (the Navajo Refinery) to its customers in the metropolitan and rural areas of Texas, New Mexico, Arizona, Colorado, 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 pipelines that transport intermediate feedstocks and crude oil from Holly s Navajo Refinery crude oil distillation and vacuum facilities in Lovington, New Mexico to its petroleum refinery facilities in Artesia, New Mexico (the Intermediate Pipelines);

- approximately 960 miles of crude oil trunk, gathering and connection pipelines located in west Texas, New Mexico and Oklahoma that deliver crude oil to Holly s Navajo Refinery;
- approximately 10 miles of crude oil and refined product pipelines that support Holly s refinery located near Salt Lake City, Utah (the Woods Cross Refinery); and
- gasoline and diesel connecting pipelines located at Holly s Tulsa refinery east facility. In 2009, Holly acquired two refinery facilities located in Tulsa, Oklahoma (collectively, the Tulsa Refinery).

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 Holly 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 truck loading rack facility at each of Holly s Navajo and Woods Cross Refineries, refined product and lube oil rail loading racks and a lube oil truck loading rack at Holly s Tulsa Refinery west facility and a refined product, asphalt and liquefied petroleum gas (LPG) truck loading rack at Holly s Tulsa Refinery east facility;
- a Roswell, New Mexico jet fuel terminal leased through September 2011;
- on-site crude oil tankage at Holly s Navajo, Woods Cross and Tulsa Refineries having an aggregate storage capacity of approximately 600,000 barrels; and
- on-site refined product tankage at Holly s Tulsa Refinery having an aggregate storage capacity of approximately 1,400,000 barrels.

We also own a 25% joint venture interest in a new 95-mile intrastate crude oil pipeline system (the SLC Pipeline) that serves refineries in the Salt Lake City area.

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

2009 Acquisitions

Sinclair Logistics and Storage Assets Transaction

On December 1, 2009, we acquired certain logistics and storage assets from an affiliate of Sinclair for $79.2 million consisting of storage tanks having approximately 1.4 million barrels of storage capacity and loading racks at Sinclair s refinery located in Tulsa, Oklahoma. 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, Holly, also a party to the transaction, acquired Sinclair s Tulsa refinery.

Concurrent with this transaction, we entered into a 15-year pipeline, tankage and loading rack throughput agreement with Holly, the Holly PTTA, whereby Holly agreed to transport, throughput and load volumes of product via our Tulsa logistics and storage assets that will initially result in minimum annual revenues to us of $13.8 million.

Roadrunner / Beeson Pipelines Transaction

Also on December 1, 2009, we acquired from Holly 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 (the Centurion Pipeline) 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).

The Roadrunner Pipeline provides the Navajo Refinery with direct access to a wide variety of crude oils available at Cushing, Oklahoma. In connection with this transaction, we entered into a 15-year pipeline agreement with Holly, the Holly RPA, whereby Holly agreed to transport volumes of crude oil on our Roadrunner Pipeline that will result in minimum annual revenues to us of $9.2 million.

The Beeson Pipeline connects our New Mexico crude oil gathering system to the Navajo Refinery Lovington facility. It operates as a component of our crude pipeline system and provides Holly with added flexibility to move crude oil from our crude oil gathering systems.

Tulsa Loading Racks Transaction

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

In connection with this transaction, we entered into a 15-year equipment and throughput agreement with Holly, the Holly ETA, whereby Holly agreed to throughput a minimum volume of products via the acquired loading racks that will initially result in minimum annual revenues to us of $2.7 million.

Lovington-Artesia Pipeline Transaction

On June 1, 2009, we acquired a newly constructed, 16-inch intermediate pipeline from Holly 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. This pipeline was placed in service effective June 1, 2009 and operates as a component of our Intermediate Pipeline system that services Holly s Navajo Refinery.

In connection with this transaction, Holly agreed to amend the Holly IPA. As a result, the term of the Holly IPA was extended by an additional 4 years and now expires in June 2024. Additionally, Holly s minimum commitment under the Holly IPA was increased and the Holly IPA currently results in minimum annual payments to us of $20.7 million.

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 Plains All American Pipeline, L.P. (Plains). The SLC Pipeline commenced operations effective March 2009 and allows various refiners in the Salt Lake City area, including Holly s Woods Cross Refinery, to ship crude oil into the Salt Lake City area from the Utah terminus of the Frontier Pipeline as well as crude oil flowing from Wyoming and Utah via Plains Rocky Mountain Pipeline. 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 Holly that was expensed as acquisition costs.

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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. Accordingly, the results of operations of Rio Grande and the $14.5 million gain on the sale are presented in discontinued operations.

2008 Acquisition

Crude Pipelines and Tankage Transaction

On February 29, 2008, we acquired from Holly certain crude pipelines and tankage assets (the Crude Pipelines and Tankage Assets) for $180 million that consist of crude oil trunk lines that deliver crude oil to Holly s Navajo Refinery in southeast New Mexico, gathering and connection pipelines located in west Texas and New Mexico, on-site crude tankage located within the Navajo and Woods Cross Refinery complexes, a jet fuel products pipeline between Artesia and Roswell, New Mexico, a leased jet fuel terminal in Roswell, New Mexico and crude oil and refined product pipelines that support Holly s Woods Cross Refinery. The consideration paid consisted of $171 million in cash and 217,497 of our common units having a fair value of $9 million.

In connection with this transaction, we entered into the 15-year Holly CPTA. Under the Holly CPTA, Holly agreed to transport and store volumes of crude oil on the crude pipelines and tankage facilities that result in minimum annual payments to us.

Agreements with Holly and Alon

We serve Holly s refineries in New Mexico, Utah and Oklahoma under several long-term pipeline and terminal, tankage and throughput agreements.

In connection with our 2009 asset acquisitions, as described above, we entered into three new 15-year transportation agreements with Holly, each expiring in 2024.

In addition, we have the Holly PTA (expiring in 2019) that relates to the pipelines and terminals contributed to us at the time of our initial public offering in 2004, the Holly IPA (expiring in 2024) that relates to the intermediate pipelines acquired from Holly in 2005 and in June 2009, and the Holly CPTA (expiring in 2023) that relates to the Crude Pipelines and Tankage Assets acquired in 2008.

Under these agreements, Holly 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 will be adjusted each year at a percentage change based upon the change in the Producer Price Index (PPI) but will not decrease as a result of a decrease in the PPI. Under these agreements, the agreed upon tariff rates are adjusted each year on July 1 at a rate based upon the percentage change in the PPI or Federal Energy Regulatory Commission (FERC) index, but with the exception of the Holly IPA, generally will not decrease as a result of a decrease in the PPI or FERC index. The FERC index is the change in the PPI plus a FERC adjustment factor that is reviewed periodically. Following our July 1, 2009 PPI rate adjustments, these agreements, including our new 2009 agreements with Holly, will result in minimum payments to us of $118.5 million for the twelve months ended June 30, 2010.

Under certain circumstances, certain of Holly s minimum revenue commitments under these agreements may be temporarily suspended or terminated.

Additionally in February 2010, we entered into a pipeline systems operating agreement with Holly expiring in 2014 (the Holly Pipeline Operating Agreement). Under the Holly Pipeline Operating Agreement, effective December 1, 2009, we will operate certain tankage, pipelines, asphalt racks and terminal buildings owned by Holly for an annual management fee of $1.3 million.

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 results in a minimum level of annual revenue. The agreed upon tariff rates are increased or decreased annually at a rate equal to the percentage change in PPI, but will not decrease below the initial $20.2 million annual amount. Following the March 1, 2009 PPI adjustment, Alon s total minimum commitment for the twelve months ending February 28, 2010 is $21.7 million. Furthermore, for the twelve months ending February 28, 2011, Alon s minimum commitment will increase to $22.7 million as a result of the upcoming March 1, 2010 PPI adjustment.

Alon s initial annual commitment was calculated based on 90% of Alon s then recent usage of these pipelines and terminals taking into account an expansion of Alon s Big Spring Refinery completed in February 2005. At revenue levels above 105% of the base revenue amount, as adjusted each year for changes in the PPI, Alon will receive an annual 50% discount on incremental revenues. Alon s obligations under the Alon PTA may be reduced or suspended under certain circumstances.

If Holly or Alon fail to meet their 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. A shortfall payment under the Holly PTA, Holly IPA and Alon PTA may be applied as a credit in the following four quarters after minimum obligations are met.

As of December 31, 2009, contractual minimums under our long-term service agreements are as follows:

Agreement		Minimum Annualized Commitment (in millions)	Year of Maturity	Contract Type
Holly PTA	$	43.7	2019	Minimum revenue commitment
Holly IPA*		20.7	2024	Minimum revenue commitment
Holly CPTA**		28.4	2023	Minimum revenue commitment
Holly PTTA		13.8	2024	Minimum revenue commitment
Holly RPA		9.2	2024	Minimum revenue commitment
Holly ETA		2.7	2024	Minimum revenue commitment
Alon PTA		21.7	2020	Minimum volume commitment
Alon capacity lease		6.4	Various	Capacity lease
Total	$	146.6		

* Reflects amended terms of the Holly IPA effective June 2009.

** Reflects amended terms of the Holly CPTA effective January 2009.

We depend on our agreements with Holly and Alon for the majority of our revenues. 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 Holly for the use of the terminals or to file for an increased tariff rate for use of the pipelines to cover Holly 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 Holly to agree on the level of the monthly surcharge or increased tariff rate.

Omnibus Agreement

We entered into an omnibus agreement with Holly in 2004 that we and Holly amended and restated several times in connection with our acquisitions from Holly in 2009 with the last amendment and restatement occurring on December 1, 2009 (the Third Restated Omnibus Agreement). Under certain provisions of the Third Restated Omnibus Agreement, we pay Holly an annual administrative fee for the provision by Holly or its affiliates of various general and administrative services to us, currently $2.3 million. This fee includes expenses incurred by Holly 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 Holly. We also reimburse Holly 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.

Under the Third Restated Omnibus Agreement, Holly agreed to indemnify us up to certain aggregate amounts for any environmental noncompliance and remediation liabilities associated with assets transferred to us and occurring or existing prior to the date of such transfers. The transfers that are covered by the agreement include the refined product pipelines, terminals and tanks transferred by Holly s subsidiaries in connection with our initial public offering in July 2004, the intermediate pipelines acquired in July 2005, and the Crude Pipelines and Tankage Assets acquired in 2008. The Third Restated Omnibus Agreement provides environmental indemnification of up to $15 million for the assets transferred to us, other than the Crude Pipelines and Tankage Assets, plus an additional $2.5 million for the intermediate pipelines acquired in July 2005. Except as described below, Holly s indemnification obligations described above will remain in effect for an asset for ten years following the date it is transferred to us. The Third Restated Omnibus Agreement also provides an additional $7.5 million of indemnification through 2023 for environmental noncompliance and remediation liabilities specific to the Crude Pipelines and Tankage Assets. Holly s indemnification obligations described above do not apply to our 2009 acquisitions consisting of (i) the Tulsa loading racks acquired from Holly, (ii) the 16-inch intermediate pipeline, (iii) the Roadrunner Pipeline, (iv) the Beeson Pipeline, or (v) the logistics and storage assets acquired from Sinclair.

Under provisions of the Holly ETA and Holly PTTA, Holly agreed to indemnify us for environmental liabilities arising from our pre-ownership operations of the Tulsa loading racks acquired from Holly in August 2009 and the Tulsa logistics and storage assets acquired from Sinclair in December 2009. Additionally, Holly agreed to indemnify us for any liabilities arising from Holly s operation of the loading racks under the Holly ETA.

We have an environmental agreement with Alon expiring in 2015 with respect to pre-closing environmental costs and liabilities relating to the pipelines and terminals acquired from Alon, whereby Alon will indemnify us subject to a $100,000 deductible and a $20 million maximum liability cap.

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, and 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 to 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 2010 capital budget is comprised of $4.8 million for maintenance capital expenditures and $6 million for expansion capital expenditures.

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We have an option agreement with Holly, granting us an option to purchase Holly s 75% equity interests in a joint venture pipeline currently under construction. The pipeline will be capable of transporting refined petroleum products from Salt Lake City, Utah to Las Vegas, Nevada (the UNEV Pipeline). Under this agreement, we have an option to purchase Holly s equity interests in the UNEV Pipeline, effective for a 180-day period commencing when the UNEV Pipeline becomes operational, at a purchase price equal to Holly s investment in the joint venture pipeline, plus interest at 7% per annum. The initial capacity of the pipeline will be 62,000 barrels per day (bpd), with the capacity for further expansion to 120,000 bpd. The total cost of the pipeline project including terminals is expected to be $275 million.

Holly currently anticipates that all requisite regulatory approvals required to commence the construction of the pipeline will be received by the start of the second quarter of 2010. Once such approvals are received, construction of the pipeline will take approximately nine months. Under this schedule, the pipeline would become operational during the first quarter of 2011.

We expect that our currently planned expenditures for sustaining and maintenance capital as well as expenditures for acquisitions and capital development projects such as the UNEV Pipeline described above, will be funded with existing cash generated by operations, the sale of additional limited partner units, the issuance of debt securities and advances under our $300 million credit agreement maturing August 2011, or a combination thereof. With volatility and uncertainty in the current 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 current 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 our credit agreement, our ability to fund some of these capital projects may be limited, especially the UNEV Pipeline. We are not obligated to purchase these assets nor are we subject to any fees or penalties if HLS board of directors decide not to proceed with any of these opportunities.

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 and 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 Holly s Navajo, Woods Cross and Tulsa Refineries, our contractual relationship with Holly under the Third Restated Omnibus Agreement and the Holly pipelines and terminals, tankage and throughput agreements, we believe that we will not face significant competition for barrels of refined products transported from Holly s Refineries, particularly during the terms of our long-term transportation agreements with Holly expiring in 2019 2024. Additionally, with our contractual relationship with Alon under the Alon PTA 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 Holly or Alon with refined products on a more competitive basis. Additionally, If Holly 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 Holly s competitors are some of the world s largest integrated petroleum companies, which have their own crude oil supplies and distribution and marketing systems. Holly 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 Holly, 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 on the basis of 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 become 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.

We inspect our pipelines regularly using equipment rented from third-party suppliers. Third parties also assist us in interpreting the results of the inspections.

Under the Third Restated Omnibus Agreement, Holly agreed to indemnify us up to certain aggregate amounts for any environmental noncompliance and remediation liabilities associated with assets transferred to us and occurring or existing prior to the date of such transfers. The transfers that are covered by the agreement include the refined product pipelines, terminals and tanks transferred by Holly s subsidiaries in connection with our initial public offering in July 2004, the intermediate pipelines acquired in July 2005, and the Crude Pipelines and Tankage Assets acquired in 2008. The Third Restated Omnibus Agreement provides environmental indemnification of up to $15 million for the assets transferred to us, other than the Crude Pipelines and Tankage Assets, plus an additional $2.5 million for the intermediate pipelines acquired in July 2005. Except as described below, Holly s indemnification obligations described above will remain in effect for an asset for ten years following the date it is transferred to us. The Third Restated Omnibus Agreement also provides an additional $7.5 million of indemnification through 2023 for environmental noncompliance and remediation liabilities specific to the Crude Pipelines and Tankage Assets. Holly s indemnification obligations described above do not apply to our 2009 acquisitions consisting of (i) the Tulsa loading racks acquired from Holly, (ii) the 16-inch intermediate pipeline, (iii) the Roadrunner Pipeline, (iv) the Beeson Pipeline, or (v) the logistics and storage assets acquired from Sinclair.

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Under provisions of the Holly ETA and Holly PTTA, Holly will indemnify us for environmental liabilities arising from our pre-ownership operations of the Tulsa loading racks acquired from Holly in August 2009 and the Tulsa logistics and storage assets acquired from Sinclair in December 2009. Additionally, Holly agreed to indemnify us for any liabilities arising from Holly s operation of the loading racks under the Holly ETA.

Additionally, 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 Holly. Certain of these projects were underway prior to our purchase and represent liabilities of Holly Corporation as the obligation for future remediation activities was retained by Holly. As of December 31, 2009, we have an accrual of $0.2 million that relates to two environmental clean-up projects. The remaining projects, including assessment and monitoring activities, are covered under the Holly environmental indemnification discussed above and represent liabilities of Holly Corporation.

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

To carry out our operations, HLS employs 140 people who provide direct support to our operations. Holly Logistic Services, L.L.C. considers its employee relations to be good. Neither we nor our general partner have employees. We reimburse Holly for direct expenses that Holly or its affiliates incurs on our behalf for the employees of HLS.

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

For the year ended December 31, 2009, Holly accounted for 70% of the revenues of our petroleum product and crude pipelines and 63% of the revenues of our terminals and truck loading racks. We expect to continue to derive a majority of our revenues from Holly for the foreseeable future. If Holly 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 the Navajo, Woods Cross or Tulsa 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, 2009, production from the Navajo Refinery accounted for 84% of the throughput volumes transported by our refined product and crude oil pipelines. The Navajo Refinery also received 100% of the petroleum products shipped on our Intermediate Pipelines. Operations at the Navajo, Woods Cross or Tulsa 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 Holly may take in response to a shutdown. Holly makes all decisions at the Navajo, Woods Cross and Tulsa 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 and capital expenditures; is responsible for all related costs; and is under no contractual obligation to us to maintain operations at its refineries.

Furthermore, Holly s obligations under the long-term pipeline and terminal, tankage and throughput agreements that it has 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 Holly 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, 2009, Alon accounted for 26% of the combined revenues of our petroleum product and crude oil 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 and capital expenditures.

In addition, under the Alon PTA, 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.

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

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. As stated above, we receive substantial revenues from both Holly and Alon under their respective pipelines and terminals, tankage and throughput agreements.

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.

We derive a significant portion of our revenues from contracts with key customers. 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.

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 Holly and/or Alon. This could reduce our opportunity to earn revenues from Holly and Alon in excess of their minimum volume commitment obligations.

An additional factor that could affect some of Holly 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 Holly and Alon to these markets.

A material decrease in the supply, or a material increase in the price, of crude oil available to Holly 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 Holly 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.

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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 2012 through 2018. Our long-term pipeline and terminal, tankage and throughput agreements with Holly and Alon expire beginning in 2019 through 2024.

Our operations may incur substantial liabilities to comply with climate change legislation.

New environmental laws and regulations, including new federal or state regulations relating to alternative energy sources and the risk of global climate change, new interpretations of existing laws and regulations, increased governmental enforcement or other developments could require us to make additional unforeseen expenditures. There is growing consensus that some form of regulation will be forthcoming at the federal level in the United States with respect to greenhouse gas emissions. Many states have already begun implementing legal measures to reduce emissions of greenhouse gases. Also, as a result of the U.S. Supreme Court s decision in April 2007 in *Massachusetts, et al. v. EPA*, the EPA may be required to regulate greenhouse gas emissions from mobile sources (*e.g.*, cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The EPA has commenced initial steps and officially proposed two sets of rules regarding the possible future regulation of greenhouse gas emissions under the Clean Air Act, one of which would regulate emissions of greenhouse gases from motor vehicles and the other of which would regulate emissions of greenhouse gases from large stationary sources such as power plants or industrial facilities. While it is not possible at this time to fully predict how legislation or new regulations that may be adopted in the United States to address greenhouse gas emissions would impact our business, new legislation or regulatory programs that restrict emissions of greenhouse gases in areas where we conduct business could adversely affect our operations and demand for our services. Furthermore, the costs of environmental and safety regulations are already significant and additional or more stringent regulation could increase these costs or could otherwise adversely affect our business.

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.

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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, injury, or extensive property damage, as well as an interruption in our operations. 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.

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.

Holly, 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.

If our assumptions concerning population growth are inaccurate or if Holly 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 Holly 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.

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If our assumptions about growth in market demand prove incorrect, Holly 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, Holly is under no obligation to pursue a growth strategy. If Holly chooses not to gain, or is unable to gain additional customers in new or existing markets in the Southwestern and Rocky Mountain regions of the United States, our growth strategy would be adversely affected. Moreover, Holly 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. Finally, Holly also will be subject to integration risks with respect to its Tulsa refining acquisitions and any new acquisitions it chooses to make.

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.

Holly 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.

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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.

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, 2009, the principal amount of our total outstanding debt was $391 million. Our results of operations, cash flows and financial position could be adversely affected by significant increases in interest rates above current levels. Various limitations in our senior secured revolving credit agreement expiring in August 2011 (the Credit Agreement) and the indentures for our 6.25% senior notes maturing March 1, 2015 (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 the 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 contribution agreements with Alon and our purchase and contribution agreements with Holly with respect to the Intermediate Pipelines and the Crude Pipelines and Tankage Assets restrict us from selling pipelines and terminals acquired from Alon or Holly, as applicable, and from prepaying more than $30 million of the Senior Notes until 2015 and $171 million in borrowings for the purchase of the Crude Pipelines and Tankage Assets until 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.

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

We may 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.

Although the domestic capital markets have shown signs of improvement in recent months, global financial markets and economic conditions have been, and continue to be, disrupted and volatile due to a variety of factors, including uncertainty in the financial services sector, low consumer confidence, increased unemployment, geopolitical issues and the current weak economic conditions. In addition, the fixed-income markets have experienced periods of extreme volatility which have 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 those 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 are experiencing increased competition for the types of assets and businesses we have historically purchased or acquired. Increased competition for a limited pool of assets could result in our losing to other bidders more often or acquiring assets at less attractive prices. Either occurrence would limit our ability to fully 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.

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 recently 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 2009, we completed several asset acquisitions, including the Sinclair Logistics Assets, the Beeson and Roadrunner Pipelines, the Tulsa Loading Racks, and the Lovington/Artesia 16-inch Pipeline. 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 and businesses we acquired in 2009. 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.

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, 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.

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 of time. 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 if any of our key senior executives or other key employees discontinues employment with us. Furthermore, a shortage of skilled labor or disruptions in our labor force may make it difficult for us to maintain labor productivity.

Our future success depends to a large extent on the services of our key senior executives and key senior employees. Our business depends on our 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.

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 Holly in connection with our initial public offering in 2004, the Intermediate Pipelines, the Crude Pipelines and Tankage Assets and the refined product pipelines, tankage and terminals transferred to us by 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 Holly at our initial public offering, through 2015 for the Intermediate Pipelines acquired from Holly and the refined product pipelines, tankage and terminals acquired from Alon, and through 2023 for the Crude Pipelines and Tankage Assets acquired from Holly. Additionally, we have entered into agreements with Holly in connection with our acquisition of the Sinclair Logistics Assets and the Tulsa Loading Racks that provide that Holly 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 Holly, 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 Holly to operate both our business and Holly s business. Our general partners officers, several of whom are also officers of Holly, will allocate the time they and the other employees of Holly spend on our behalf and on behalf of Holly. 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

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

Currently, Holly indirectly owns the 2% general partner interest and a 32% limited partner interest in us and owns and controls the general partner of our general partner, HEP Logistics Holdings, L.P. Conflicts of interest may arise between Holly 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:

- Holly, 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 Holly 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. Holly s directors and officers have a fiduciary duty to make these decisions in the best interests of the stockholders of Holly;
- our general partner is allowed to take into account the interests of parties other than us, such as Holly, in resolving conflicts of interest;
- our general partner determines which costs incurred by Holly 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 Holly.

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 Holly an administrative fee of $2.3 million per year for the provision by Holly or its affiliates of various general and administrative services for our benefit. We can provide no assurance that Holly 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 Holly 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 Holly 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.

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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.

In August 2009, all of the conditions necessary to end the subordination period for the 7,000,000 subordinated units owned by our general partner were met and the units were converted into our common units on a one-for-one basis. In addition, under our partnership agreement, because the subordination period for this class of subordinated units has expired, 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 $860 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.

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

Holly and its affiliates may engage in limited competition with us. Pursuant to the Third Restated Omnibus Agreement among us, Holly and our general partner, Holly 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 Third Restated Omnibus Agreement, however, does not apply to:

- any business operated by Holly or any of its subsidiaries at the closing of our initial public offering;
- any business or asset that Holly or any of it subsidiaries acquires or constructs that has a fair market value or construction cost of less than $5 million; and
- any business or asset that Holly 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 Holly or its affiliates no longer control our partnership or there is a change of control of Holly, the non-competition provisions of the Third Restated 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 Holly 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 an undesirable time or price 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.

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 we were to become subject to additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on 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, legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships. It could be amended prior to enactment in a manner that does apply to us. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. 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.

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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 understates deductions available to those unitholders who own those common units and results in a reduction in the tax basis of those common units by the amount of the deductions that were allowable but were not taken.

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 this 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. Recently, however, the Department of the Treasury and the IRS 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 among transferor and transferee unitholders. Although existing publicly traded partnerships are entitled to rely on these proposed Treasury Regulations, they are not binding on the IRS and are subject to change until final Treasury Regulations are issued.

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 additional 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.

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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 announced recently that it plans to issue guidance regarding the treatment of constructive terminations of publicly traded partnerships such as us. Any such guidance may change the application of the rules discussed above and may affect the treatment of a unitholder.

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, Colorado, 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.

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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 Holly 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, Colorado, 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 Holly s Navajo Refinery Lovington facilities and terminate at its Artesia facilities. These pipelines transport intermediate feedstocks and crude oil for Holly 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 Holly s Navajo Refinery and crude oil and refined product pipelines that support Holly 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 Holly 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.

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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 Holly and for third parties.

	Years Ended December 31,				
	2009(3)	**2008**(2)	**2007**	**2006**	**2005**(1)
Volumes transported for (bpd):					
Holly	295,039	253,484	142,447	126,929	94,473
Third parties(4)	43,709	22,756	46,511	47,551	49,298
Total	338,748	276,240	188,958	174,480	143,771
Total barrels in thousands (mbbls(4))	118,742	95,404	63,053	63,685	52,477

(1) Includes volumes transported on the pipelines acquired from Alon on February 28, 2005, and volumes transported on the Intermediate Pipelines acquired on July 8, 2005.

(2) Includes volumes transported on the Crude Pipelines acquired February 29, 2008.

(3) Includes volumes transported on the Roadrunner and Beeson Pipelines acquired December 1, 2009.

(4) *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 crude oil and petroleum product 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 17,500 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
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 17,500 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.*

Holly shipped an aggregate of 67% 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 2009. These pipelines transported 95% of the light refined products produced by Holly s Navajo Refinery in 2009.

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 Holly s 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. The refined products shipped on this pipeline represented 13% of the total light refined products produced at Holly s Navajo Refinery during 2009. Refined products produced at Holly s 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 Holly s 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, Holly and Alon. In 2009, this pipeline transported to our El Paso terminal 63% of the light refined products produced at Holly s Navajo Refinery. As mentioned above, refined products destined to the 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 Holly s 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). Holly 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 $504,000 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). Holly 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 Alon s 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 Alon s 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 Alon s 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. Holly 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 and 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 the Woods Cross Refinery to Chevron s North Salt Lake pumping station. Holly 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 Holly s Navajo Refinery Lovington facility to its Artesia facility. Holly 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 Holly s Navajo Refinery Lovington facility to its Artesia facility. Holly 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 Holly s Navajo Refinery Lovington facility to its Artesia facility. Holly 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 the Navajo Refinery and consists of 850 miles of 4-inch, 6-inch and 8-inch diameter pipeline. The crude oil trunk pipelines consists 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.

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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 Holly s 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 Lovington facility.

Beeson Pipeline

The Beeson crude oil pipeline delivers crude oil to Holly s 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 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 Holly s 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 Holly s Navajo and Woods Cross Refineries and Alon s Big Spring Refinery. We then distribute them to Holly 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 Holly 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. Holly currently accounts for the substantial majority of our refined product terminal revenues.

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

	Years Ended December 31,				
	2009(2)	**2008**	**2007**	**2006**	**2005**(1)
Refined products terminalled for (bpd):					
Holly	114,431	109,539	119,910	118,202	120,795
Third parties	42,206	32,737	45,457	43,285	42,334
Total	156,637	142,276	165,367	161,487	163,129
Total (mbbls)	57,173	52,073	60,344	58,943	59,542

(1) *Includes volumes for the terminals and tank farm acquired from Alon February 28, 2005.*

(2) *Includes throughput volumes attributable to the Tulsa rack facilities acquired in August and December 2009.*

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
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 rack	N/A	N/A	Refinery	Truck/Pipeline
Total	2,446,000			

(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 Holly s Navajo Refinery Artesia facility through our Artesia to El Paso and Artesia to Orla to El Paso pipelines and by rail that account for 92% of the volumes at this terminal. We also receive product from Alon s Big Spring Refinery that accounted for 8% of the volumes at this terminal in 2009. 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 Holly s Navajo Refinery Artesia facility through our pipelines. Refined products received at this terminal are sold locally, via the truck rack; Holly is our only customer at this terminal. There are no competing terminals in Moriarty.

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Bloomfield Terminal

We receive light refined products at this terminal from Holly s Navajo Refinery Artesia facility through our pipelines. Refined products received at this terminal are sold locally, via the truck rack; Holly is our only customer at this terminal.

Tucson Terminal

We own 100% of the improvements and lease underlying ground at this terminal. The Tucson terminal receives light refined products from Kinder Morgan s East System pipeline, which transports refined products from Holly s 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 Holly 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. Holly 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 Holly 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. Holly and Sinclair are the only customers at this terminal.

Spokane Terminal

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

Abilene Terminal

This terminal receives refined products from Alon s Big Spring Refinery, which accounted for all of its volumes in 2009. 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 Alon s Big Spring Refinery, which accounted for all of its volumes in 2009. 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 Holly s Navajo Refinery, which accounted for all of its volumes in 2009, for further transport to Cannon Air Force Base and to Albuquerque, New Mexico. We lease this terminal under an agreement that expires in September 2011.

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Orla Tank Farm

The Orla tank farm was constructed in 1998. It receives refined products from Alon s Big Spring Refinery that accounted for all of its volumes in 2009. 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 Holly s Navajo Refinery Artesia facility loads light refined products, produced at the facility, onto tanker trucks for delivery to markets in the surrounding area. Holly is the only customer of this truck rack.

Woods Cross Facility Truck Rack

The truck rack at Holly s Woods Cross facility loads light refined products produced at Holly s Woods Cross Refinery onto tanker trucks for delivery to markets in the surrounding area. Holly is the only customer of this truck rack. Holly 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 Holly s Tulsa Refinery west and east facilities. Loading racks at the Tulsa Refinery s west facility consist of rail racks that load refined products and lube oil produced at Holly s Tulsa Refinery onto rail car and a truck rack that loads lube oil onto tanker trucks. The truck rack at Holly s Tulsa Refinery east facility loads refined products, asphalt and LPG onto tanker trucks for further delivery.

Refinery Tankage

Our refinery tankage consists of on-site tankage at Holly s Navajo, Woods Cross and Tulsa Refineries. Our refinery tankage derives its revenues from fixed fees or throughput charges in providing Holly s refining facilities with approximately 2,000,000 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	1,363,000	Refined product	26
Total	1,976,000		

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TRUCK FLEET

We have a truck fleet consisting of 7 trucks and 13 trailers that transport crude oil to Holly s Wood Cross Refinery. Our trucking operations are conducted in Utah only, and Holly 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. Submission of Matters to a Vote of Security Holders

No matter was submitted to a vote of security holders during the fourth quarter of 2009.

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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
2009				
Fourth quarter	$ 41.65	$ 35.21	$ 0.805	5,548,600
Third quarter	$ 40.05	$ 31.30	$ 0.795	2,296,400
Second quarter	$ 33.29	$ 23.19	$ 0.785	5,544,700
First quarter	$ 30.43	$ 20.96	$ 0.775	2,632,700
2008				
Fourth quarter	$ 33.46	$ 14.93	$ 0.765	3,901,900
Third quarter	$ 39.16	$ 26.01	$ 0.755	2,537,800
Second quarter	$ 47.03	$ 37.33	$ 0.745	1,914,000
First quarter	$ 44.23	$ 36.06	$ 0.735	1,384,400

(1) Represents cash distributions attributable to each of the quarters in the years ended December 31, 2009 and 2008. Distributions are declared and paid within 45 days following the close of each quarter.

The cash distribution for the fourth quarter of 2009 was declared on January 27, 2010 and is payable on February 12, 2010 to all unitholders of record on February 5, 2010.

As of February 8, 2010, we had approximately 9,530 common unitholders, including beneficial owners of common units held in street name.

We consider 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. Our revolving credit facility prohibits us from making cash distributions if any potential default or event of default, as defined in the Credit Agreement, occurs or would result from the cash distribution. The indenture relating to our 6.25% Senior Notes prohibits us from making cash distributions under certain circumstances.

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 law, 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. Working capital borrowings are generally borrowings that are made under our revolving credit facility and in all cases are used solely for working capital purposes or to pay distributions to partners.

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We make distributions of available cash from operating surplus for any quarter during which we have outstanding subordinated units in the following manner: first, 98% to the 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; second, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period; third, 98% to the subordinated unitholders, pro rata, and 2% to the general partner, until we distribute for each subordinated unit an amount equal to the minimum quarterly distribution for that quarter; and thereafter, cash in excess of the minimum quarterly distributions is distributed to the unitholders and the general partner based on the percentages below.
The general partner, HEP Logistics Holdings, L.P., is entitled to incentive distributions if the amount we distribute with respect to any quarter exceeds specified target levels shown below:

	Total Quarterly Distribution	Marginal Percentage Interest in Distributions	
	Target Amount	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%

In August 2009, all of the conditions necessary to end the subordination period for the 7,000,000 subordinated units owned by Holly were met and the units were converted into our common units on a one-for-one basis. However, currently, there are 937,500 of our Class B subordinated units that are outstanding and owned by Alon. The subordinated period of these units extends until the first day of any quarter beginning after March 31, 2010 provided Alon is not in default with respect to payments due under its minimum volume commitments under the Alon PTA for each of the three consecutive, non-overlapping four-quarter periods immediately preceding such date. At the end of the subordination period, the Class B subordinated units will convert into our common units on a one-for-one basis. These subordinated units are not publicly traded.

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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,				
	2009	2008	2007	2006	2005
	(In thousands, except per unit data)				
Statement Of Income Data:					
Revenues	$ 146,561	$ 108,822	$ 96,190	$ 80,794	$ 71,350
Operating costs and expenses					
Operations	44,003	38,920	30,467	26,966	23,209
Depreciation and amortization	26,714	21,937	12,920	12,833	11,133
General and administrative	7,586	6,380	4,914	4,849	4,030
	78,303	67,237	48,301	44,648	38,372
Operating income	68,258	41,585	47,889	36,146	32,978
Equity in earnings of SLC Pipeline	1,919				
SLC Pipeline acquisition costs	(2,500)				
Interest income	11	118	454	899	633
Interest expense	(21,501)	(21,763)	(13,289)	(13,056)	(9,633)
Gain on sale of assets		36	298		
Other income	67	990			
	(22,004)	(20,619)	(12,537)	(12,157)	(9,000)
Income from continuing operations before income taxes	46,254	20,966	35,352	23,989	23,978
State income tax	(20)	(270)	(200)		
Income from continuing operations	46,234	20,696	35,152	23,989	23,978
Income from discontinued operations, net of noncontrolling interest[1]	19,780	4,671	4,119	3,554	2,838
Net income	66,014	25,367	39,271	27,543	26,816
Less general partner interest in net income, including incentive distributions[2]	7,947	3,913	3,166	1,858	1,155
Limited partners interest in net income	$ 58,067	$ 21,454	$ 36,105	$ 25,685	$ 25,661
Limited partners per unit interest in net income basic and diluted[2][3]	$ 3.18	$ 1.32	$ 2.24	$ 1.59	$ 1.67
Distributions per limited partner unit	$ 3.16	$ 3.00	$ 2.835	$ 2.635	$ 2.35

Other Financial Data:					
EBITDA[(4)]	$ 100,707	$ 70,195	$ 66,684	$ 55,030	$ 50,001
Distributable cash flow[(5)]	$ 72,213	$ 60,365	$ 51,012	$ 47,219	$ 42,451
Cash flows from operating activities	$ 68,195	$ 63,651	$ 59,056	$ 45,853	$ 42,628
Cash flows from investing activities	$ (147,379)	$ (213,267)	$ (9,632)	$ (9,107)	$ (131,795)
Cash flows from financing activities	$ 76,423	$ 144,564	$ (50,658)	$ (45,774)	$ 90,646
Maintenance capital expenditures[(5)]	$ 3,595	$ 3,133	$ 1,863	$ 1,095	$ 364
Expansion capital expenditures	150,149	210,170	8,094	8,012	3,519
Total capital expenditures	$ 153,744	$ 213,303	$ 9,957	$ 9,107	$ 3,883
Balance Sheet Data (at period end):					
Net property, plant and equipment	$ 398,044	$ 257,886	$ 125,384	$ 127,357	$ 128,077
Total assets	$ 616,845	$ 439,688	$ 238,904	$ 245,771	$ 254,775
Long-term debt[(6)]	$ 390,827	$ 355,793	$ 181,435	$ 180,660	$ 180,737
Total liabilities	$ 422,981	$ 431,568	$ 200,348	$ 198,582	$ 190,962
Total equity (deficit)[(7)]	$ 193,864	$ 8,120	$ 38,556	$ 47,189	$ 63,813

(1) On December 1, 2009, we sold our 70% interest in Rio Grande. Accordingly, results of operations of Rio Grande are presented in discontinued operations. Additionally, pipeline volume information excludes volumes attributable to Rio Grande.

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

(3) New accounting standards became effective January 1, 2009 that prescribe the application of the two-class method in computing earnings per unit to reflect a master limited partnership s contractual obligation to make distributions to the general

partner, limited partners and incentive distribution rights holders. As a result, our quarterly earnings allocations to the general partner now include incentive distributions that were declared subsequent to quarter end. Prior to our adoption of these standards, our general partner earnings allocations included incentive distributions that were declared during each quarter. We have applied these standards on a retrospective basis. The application of these standards resulted in a decrease in our limited partners interest in net income of $0.02, $0.02, $0.01 and $0.03 for the years ended December 31, 2008, 2007, 2006 and 2005, respectively.

(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,				
	2009	**2008**	**2007**	**2006**	**2005**
	(In thousands)				
Income from continuing operations	$ 46,234	$ 20,696	$ 35,152	$ 23,989	$ 23,978
Add (subtract):					
Interest expense	20,620	18,479	12,281	12,088	8,848
Amortization of discount and deferred debt issuance costs	706	1,002	1,008	968	785
Increase in interest expense change in fair value of interest rate swaps	175	2,282			
Interest income	(11)	(118)	(454)	(899)	(633)
State income tax	20	270	200		
Depreciation and amortization	26,714	21,937	12,920	12,833	11,133
EBITDA from discontinued operations (excludes gain on sale of Rio Grande)	6,249	5,647	5,577	6,051	5,890
EBITDA	$ 100,707	$ 70,195	$ 66,684	$ 55,030	$ 50,001

(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 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. We believe that this measure provides investors an enhanced perspective of the operating performance of our assets and the cash our business is generating.

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Set forth below is our calculation of distributable cash flow.

	Years Ended December 31,				
	2009	2008	2007	2006	2005
	(In thousands)				
Income from continuing operations	$ 46,234	$ 20,696	$ 35,152	$ 23,989	$ 23,978
Add (subtract):					
Depreciation and amortization	26,714	21,937	12,920	12,833	11,133
Amortization of discount and deferred debt issuance costs	706	1,002	1,008	968	785
Increase in interest expense change in fair value of interest rate swaps	175	2,282			
Equity in excess cash flows over earnings of SLC Pipeline	552				
Increase (decrease) in deferred revenue	(7,256)	11,958	(1,786)	4,473	1,013
SLC Pipeline acquisition costs*	2,500				
Maintenance capital expenditures**	(3,595)	(3,133)	(1,863)	(1,095)	(364)
Distributable cash flow from discontinued operations (excludes gain on sale of Rio Grande)	6,183	5,623	5,581	6,051	5,906
Distributable cash flow	$ 72,213	$ 60,365	$ 51,012	$ 47,219	$ 42,451

* Under accounting standards, effective January 1, 2009, 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. As

these costs directly relate to our interest in the new joint venture pipeline and are similar to expansion capital expenditures, we have added back these costs to arrive at distributable cash flow.

** 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, and safety and to address environmental regulations.

(6) Includes $206 million and

$171 million in credit agreement advances that were classified as long-term debt at December 31, 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 equity since our regular quarterly distributions have exceeded our quarterly net income. Additionally, if the assets transferred to us upon our initial public offering in 2004, the intermediate pipelines purchased from Holly in 2005 and the assets purchased from Holly in 2009 had been acquired from third parties, our acquisition cost

in excess of Holly s basis in the transferred assets of $160.4 million would have been recorded as increases to our properties and equipment and intangible assets instead of reductions to equity.

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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 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 substantially all of the petroleum product and crude oil pipeline and terminal, tankage and loading rack facilities that support Holly s refining and marketing operations in west Texas, New Mexico, Utah, Oklahoma, Idaho and Arizona. Holly currently owns a 34% interest in us. We also own and operate refined product pipelines and terminals, located primarily in Texas, that service Alon s Big Spring Refinery in Big Spring, Texas.

We generate revenues by charging tariffs for transporting petroleum products and crude oil through our pipelines, by charging fees for terminalling refined products and other hydrocarbons and storing 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.

2009 Acquisitions

Sinclair Logistics and Storage Assets Transaction

On December 1, 2009, we acquired certain logistics and storage assets from an affiliate of Sinclair for $79.2 million consisting of storage tanks having approximately 1.4 million barrels of storage capacity and loading racks at Sinclair s refinery located in Tulsa, Oklahoma. 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.

Roadrunner / Beeson Pipelines Transaction

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

Tulsa Loading Racks Transaction

On August 1, 2009, we acquired from Holly certain truck and rail loading/unloading facilities located at Holly s Tulsa Refinery 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 a newly constructed, 16-inch intermediate pipeline from Holly 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.

SLC Pipeline Joint Venture Interest Transaction

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 Plains. The SLC Pipeline commenced operations effective March 2009 and allows various refiners in the Salt Lake City area, including Holly s Woods Cross Refinery, to ship crude oil into the Salt Lake City area from the Utah terminus of the Frontier Pipeline as well as crude oil flowing from Wyoming and Utah via Plains Rocky Mountain Pipeline. 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 Holly that was expensed as acquisition costs.

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Also in March 2009 Holly, our largest customer, completed a 15,000 bpd capacity expansion of its Navajo Refinery increasing refining capacity to 100,000 bpd, or by 18%.

Rio Grande Pipeline Sale

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

2008 Acquisition

Crude Pipelines and Tankage Transaction

In February 2008, we acquired from Holly, the Crude Pipelines and Tankage Assets for $180 million. The Crude Pipelines and Tankage Assets primarily consist of crude oil trunk lines and gathering lines, product and crude oil pipelines and tankage that service Holly s Navajo and Woods Cross Refineries and a leased jet fuel terminal.

Agreements with Holly and Alon

We serve Holly s refineries in New Mexico, Utah and Oklahoma under several long-term pipeline and terminal, tankage and throughput agreements.

In connection with our 2009 asset acquisitions, as described above we entered into three new 15-year transportation agreements with Holly, each expiring in 2024. We entered into the Holly PTTA whereby Holly agreed to transport, throughput and load volumes of product via our logistics and storage assets acquired from Sinclair that are located at Holly s Tulsa Refinery. Additionally, we entered into the Holly RPA that relates to the Roadrunner Pipeline acquired from Holly in December 2009 and the Holly ETA that relates to the Tulsa loading racks acquired from Holly in August 2009.

In addition, we have the Holly PTA (expiring in 2019) that relates to the pipelines and terminals contributed to us at the time of our initial public offering in 2004, the Holly IPA (expiring in 2024) that relates to the Intermediate Pipelines acquired in 2005 and in June 2009, and the Holly CPTA (expiring in 2023) that relates to the Crude Pipelines and Tankage Assets acquired in 2008.

Under these agreements, Holly 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 will be adjusted each year at a percentage change based upon the change in the PPI but will not decrease as a result of a decrease in the PPI. Under these agreements, the agreed upon tariff rates are adjusted each year on July 1 at a rate based upon the percentage change in the PPI or FERC index, but with the exception of the Holly IPA, generally will not decrease as a result of a decrease in the PPI or FERC index. The FERC index is the change in the PPI plus a FERC adjustment factor that is reviewed periodically.

Additionally in February 2010, we entered into a pipeline systems operating agreement with Holly expiring in 2014. Under the Holly Pipeline Operating Agreement, effective December 1, 2009, we will operate certain tankage, pipelines, asphalt racks and terminal buildings owned by Holly for an annual management fee of $1.3 million.

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 results in a minimum level of annual revenue. The agreed upon tariff rates are increased or decreased annually at a rate equal to the percentage change in PPI, but not below the initial tariff rate.

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At December 31, 2009, contractual minimums under our long-term service agreements are as follows:

Agreement	Minimum Annualized Commitment (In millions)	Year of Maturity	Contract Type
Holly PTA	$ 43.7	2019	Minimum revenue commitment
Holly IPA*	20.7	2024	Minimum revenue commitment
Holly CPTA**	28.4	2023	Minimum revenue commitment
Holly PTTA	13.8	2024	Minimum revenue commitment
Holly RPA	9.2	2024	Minimum revenue commitment
Holly ETA	2.7	2024	Minimum revenue commitment
Alon PTA	21.7	2020	Minimum volume commitment
Alon capacity lease	6.4	Various	Capacity lease
Total	$ 146.6		

* Reflects amended terms of the Holly IPA effective June 2009.

** Reflects amended terms of the Holly CPTA effective January 2009.

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

Under certain provisions of the Third Restated Omnibus Agreement that we have with Holly, we pay Holly an annual administrative fee, currently $2.3 million, for the provision by Holly 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 Holly. We also reimburse Holly and its affiliates for direct expenses they incur on our behalf.

Please read Agreements with Holly under Item 1, Business for additional information on these agreements with Holly and Alon.

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RESULTS OF OPERATIONS

The following tables present our operating income, volume information and cash flow summary information for the years ended December 31, 2009, 2008 and 2007.

	Years Ended December 31, 2009	2008	Change from 2008
	(In thousands, except per unit data)		
Revenues			
Pipelines:			
Affiliates refined product pipelines	$ 43,206	$ 40,446	$ 2,760
Affiliates intermediate pipelines	16,362	11,917	4,445
Affiliates crude pipelines	29,266	22,380	6,886
	88,834	74,743	14,091
Third parties refined product pipelines	37,930	19,314	18,616
	126,764	94,057	32,707
Terminals and loading racks:			
Affiliates	12,561	10,297	2,264
Third parties	7,236	4,468	2,768
	19,797	14,765	5,032
Total revenues	146,561	108,822	37,739
Operating costs and expenses			
Operations	44,003	38,920	5,083
Depreciation and amortization	26,714	21,937	4,777
General and administrative	7,586	6,380	1,206
	78,303	67,237	11,066
Operating income	68,258	41,585	26,673
Equity in earnings of SLC Pipeline	1,919		1,919
SLC Pipeline acquisition costs	(2,500)		(2,500)
Interest income	11	118	(107)
Interest expense, including amortization	(21,501)	(21,763)	262
Gain on sale of assets		36	(36)
Other income	67	990	(923)
	(22,004)	(20,619)	(1,385)

Income from continuing operations before income taxes		46,254		20,966		25,288
State income tax		(20)		(270)		250
Income from continuing operations		46,234		20,696		25,538
Discontinued operations[1]						
Income from discontinued operations, net of noncontrolling interest of $1,579 and $1,278 for the years ended December 31, 2009 and 2008, respectively		5,301		4,671		630
Gain on sale of interest in Rio Grande		14,479				14,479
Income from discontinued operations		19,780		4,671		15,109
Net income		66,014		25,367		40,647
Less general partner interest in net income, including incentive distributions [2]		7,947		3,913		4,034
Limited partners interest in net income	$	58,067	$	21,454	$	36,613
Limited partners earnings per unit basic and diluted[2][3]						
Income from continuing operations	$	2.12	$	1.04	$	1.08
Income from discontinued operations		0.28		0.28		
Gain on sale of discontinued operations		0.78				0.78
Net income	$	3.18	$	1.32	$	1.86
Weighted average limited partners units outstanding		18,268		16,291		1,977
EBITDA[4]	$	100,707	$	70,195	$	30,512
Distributable cash flow[5]	$	72,213	$	60,365	$	11,848
Volumes from continuing operations (bpd)[1][6]						
Pipelines:						
Affiliates refined product pipelines		88,001		83,203		4,798
Affiliates intermediate pipelines		69,794		58,855		10,939
Affiliates crude pipelines		137,244		111,426		25,818
		295,039		253,484		41,555
Third parties refined product pipelines		43,709		22,756		20,953

	338,748	276,240	62,508
Terminals and loading racks:			
Affiliates	114,431	109,539	4,892
Third parties	42,206	32,737	9,469
	156,637	142,276	14,361
Total for pipelines and terminal assets (bpd)	495,385	418,516	76,869

	Years Ended December 31, 2008	Years Ended December 31, 2007	Change from 2008
	(In thousands, except per unit data)		
Revenues			
Pipelines:			
Affiliates refined product pipelines	$ 40,446	$ 36,281	$ 4,165
Affiliates intermediate pipelines	11,917	13,731	(1,814)
Affiliates crude pipelines	22,380		22,380
	74,743	50,012	24,731
Third parties refined product pipelines	19,314	27,054	(7,740)
	94,057	77,066	16,991
Terminals and loading racks:			
Affiliates	10,297	10,949	(652)
Third parties	4,468	5,427	(959)
	14,765	16,376	(1,611)
Other affiliates		2,748	(2,748)
Total revenues	108,822	96,190	12,632
Operating costs and expenses			
Operations	38,920	30,467	8,453
Depreciation and amortization	21,937	12,920	9,017
General and administrative	6,380	4,914	1,466
	67,237	48,301	18,936
Operating income	41,585	47,889	(6,304)
Interest income	118	454	(336)
Interest expense, including amortization	(21,763)	(13,289)	(8,474)
Gain on sale of assets	36	298	(262)
Other income	990		990
	(20,619)	(12,537)	(8,082)
Income from continuing operations before income taxes	20,966	35,352	(14,386)
State income tax	(270)	(200)	(70)

Income from continuing operations		20,696		35,152		(14,456)
Income from discontinued operations, net of noncontrolling interest of $1,278 and $1,067 for the years ended December 31, 2008 and 2007, respectively[1]		4,671		4,119		552
Net income		25,367		39,271		(13,904)
Less general partner interest in net income, including incentive distributions [2]		3,913		3,166		747
Limited partners interest in net income	$	21,454	$	36,105	$	(14,651)
Limited partners earnings per unit basic and diluted[2][3]						
Income from continuing operations	$	1.04	$	1.99	$	(0.95)
Income from discontinued operations		0.28		0.25		0.03
Net income	$	1.32	$	2.24	$	(0.92)
Weighted average limited partners units outstanding		16,291		16,108		183
EBITDA[4]	$	70,195	$	66,610	$	3,585
Distributable cash flow[5]	$	60,365	$	51,012	$	9,353
Volumes from continuing operations (bpd)[1]						
Pipelines:						
Affiliates refined product pipelines		83,203		77,441		5,762
Affiliates intermediate pipelines		58,855		65,006		(6,151)
Affiliates crude pipelines		111,426				111,426
		253,484		142,447		111,037
Third parties refined product pipelines		22,756		46,511		(23,755)
		276,240		188,958		87,282
Terminals and loading racks:						
Affiliates		109,539		119,910		(10,371)
Third parties		32,737		45,457		(12,720)
		142,276		165,367		(23,091)
Total for pipelines and terminal assets (bpd)		418,516		354,325		64,191

(1) On December 1, 2009, we sold our 70% interest in Rio Grande. Accordingly, results of operations of Rio Grande are presented in discontinued operations. Additionally, pipeline volume information excludes volumes attributable to Rio Grande.

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

(3) New accounting standards became effective January 1, 2009 that prescribe the application of the two-class method in computing earnings per unit to reflect a master limited partnership s contractual obligation to make distributions to the general

partner, limited partners and incentive distribution rights holders. As a result, our quarterly earnings allocations to the general partner now include incentive distributions that were declared subsequent to quarter end. Prior to our adoption of these standards, our general partner earnings allocations included incentive distributions that were declared during each quarter. We have applied these standards on a retrospective basis. The application of these standards resulted in a decrease in our limited partners per unit interest in net income of $0.02 for each of the years ended December 31, 2008 and 2007.

(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. 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, 2009 Compared with Year Ended December 31, 2008

Summary

Income from continuing operations for the year ended December 31, 2009 was $46.2 million, a $25.5 million increase compared to the year ended December 31, 2008. This increase in overall earnings was due principally to overall increased shipments on our pipeline systems, earnings attributable to our current year asset acquisitions, the effect of the annual tariff increase on affiliate pipeline shipments and an increase in previously deferred revenue realized. Our revenues for the year ended December 31, 2009 include the recognition of $15.7 million of prior shortfalls billed to shippers in 2008 as they did not meet their minimum volume commitments in any of the subsequent four quarters. Revenues of $8.4 million relating to deficiency payments associated with certain guaranteed shipping contracts was deferred during the year ended December 31, 2009. Such deferred revenue will be recognized in 2010 either as payment for shipments in excess of guaranteed levels or when shipping rights expire unused after a twelve-month period.

Revenues

Total revenues from continuing operations for the year ended December 31, 2009 were $146.6 million, a $37.7 million increase compared to the year ended December 31, 2008. This increase was due principally to overall increased shipments on our pipeline systems, increased revenues attributable to our crude pipeline assets acquired in the first quarter of 2008, the effect of annual tariff increases on affiliate pipeline shipments, an increase in previously deferred revenue realized and revenues attributable to our newly acquired Tulsa facilities. Increased volumes attributable to Holly s 15,000 barrels per stream day Navajo Refinery expansion in the first quarter of 2009, including volumes shipped on our new 16-inch intermediate and Beeson pipelines contributed to an increase in affiliate pipeline shipments. Affiliate shipments for the year ended December 31, 2009 were also impacted by the effects of reduced production during Holly s planned maintenance turnaround of its Navajo Refinery in the first quarter of 2009. Additionally, third-party refined product shipments were up for 2009 compared to last year s, which were down as a result of limited production resulting from an explosion and fire at Alon s Big Spring Refinery in the first quarter of 2008.

On February 18, 2008, Alon experienced an explosion and fire at its Big Spring Refinery that resulted in the shutdown of production. In early April 2008, Alon reopened its Big Spring Refinery and resumed production at approximately one-half of refining capacity until production was restored in late September and later increased to full capacity during the fourth quarter of 2008. Lost production and reduced operations attributable to this incident resulted in a decrease in third-party shipments on our refined product pipelines during the first nine months of 2008.

Revenues from our refined product pipelines were $81.1 million, an increase of $21.4 million compared to the year ended December 31, 2008. This increase was due to increased shipments on our refined product pipeline system, the effect of the annual tariff increase on affiliate refined product shipments and a $10.7 million increase in previously deferred revenue realized. Shipments on our refined product pipeline system increased to an average of 131.7 thousand barrels per day (mbpd) compared to 106 mbpd for the same period last year.

Revenues from our intermediate pipelines were $16.4 million, an increase of $4.4 million compared to the year ended December 31, 2008. This increase was due to increased shipments on our intermediate pipeline system including volumes shipped on our new 16-inch pipeline, the effect of the annual tariff increase on intermediate pipeline shipments and a $1.1 million increase in previously deferred revenue realized. Shipments on our intermediate product pipeline system increased to an average of 69.8 mbpd compared to 58.9 mbpd for the same period last year.

Revenues from our crude pipelines were $29.3 million, an increase of $6.9 million compared to the year ended December 31, 2008. This increase was due to the realization of revenues from crude oil shipments for a full twelve-month period during the year ended December 31, 2009 compared to ten months of shipments during the same period last year due to the commencement of operations on March 1, 2008, increased shipments on our crude pipeline system and the effect of the annual tariff increase. Additionally, this increase includes $0.8 million in revenues attributable to our Roadrunner Pipeline transportation agreement with Holly. Shipments on our crude pipeline system increased to an average of 137.2 mbpd during the year ended December 31, 2009 compared to 111.4 mbpd for the same period last year.

Revenues from terminal, tankage and loading rack fees were $19.8 million, an increase of $5 million compared to the year ended December 31, 2008. This increase includes $2.5 million in revenues attributable to our volumes transferred via our newly acquired Tulsa facilities. Refined products terminalled in our facilities increased to an average of 156.6 mbpd compared to 142.3 mbpd for the same period last year.

Operations Expense

Operations expense for the year ended December 31, 2009 increased by $5.1 million compared to the year ended December 31, 2008. This increase was due principally to costs attributable to higher throughput volumes, including those from our 2009 asset acquisitions, and higher maintenance and payroll expense.

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Depreciation and Amortization
Depreciation and amortization for the year ended December 31, 2009 increased by $4.8 million compared to the year ended December 31, 2008. This was due to increased depreciation attributable to our 2009 and 2008 asset acquisitions and capital projects.

General and Administrative
General and administrative costs for the year ended December 31, 2009 increased by $1.2 million compared to the year ended December 31, 2008, due principally to increased professional fees related to our 2009 asset acquisitions.

Equity in Earnings of SLC Pipeline
The SLC Pipeline commenced pipeline operations effective March 2009. Our equity in earnings of the SLC Pipeline was $1.9 million for the year ended December 31, 2009.

SLC Pipeline Acquisition Costs
We incurred a $2.5 million finder s fee in connection with the acquisition our SLC Pipeline joint venture interest. 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, 2009 totaled $21.5 million, a decrease of $0.3 million compared to the year ended December 31, 2008. For the years ended December 31, 2009 and 2008, fair value adjustments to our interest rate swaps resulted in $0.2 million and $2.3 million, respectively, in non-cash interest expense. Excluding the effects of these fair value adjustments, our aggregate effective interest rate was 5.3% for the year ended December 31, 2009 compared to 5.4% for 2008.

State Income Tax
We recorded state income taxes of $20,000 and $270,000 for the years ended December 31, 2009 and 2008, 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
Income from discontinued operations for the year ended December 31, 2009 includes the gain from the sale of our 70% interest in Rio Grande of $14.5 million. Rio Grande operations generated $6.9 million of earnings for the period from January through November 2009 compared to $5.9 million for the year ended December 31, 2008. Rio Grande earnings for the years ended December 31, 2009 and 2008 are presented net of earnings attributable to noncontrolling interest holders of $1.6 million and $1.3 million, respectively.

Results of Operations Year Ended December 31, 2008 Compared with Year Ended December 31, 2007

Summary
Net income for the year ended December 31, 2008 was $25.4 million, a $13.9 million decrease compared to the year ended December 31, 2007. This decrease in overall earnings was due principally to the effects of limited production at Alon s Big Spring Refinery resulting from an explosion and fire in February 2008, a decrease in previously deferred revenue realized and an increase in operating costs and expenses and interest expense. These factors were partially offset by earnings attributable to our crude pipeline assets acquired in the first quarter of 2008, the effect of the annual tariff increases and an increase in affiliate refined product shipments. Revenues of $15.7 million relating to deficiency payments associated with certain guaranteed shipping contracts was deferred during the year ended December 31, 2008. Such deferred revenue was recognized in 2009 when shipping rights expired unused after a twelve-month period.

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Revenues

Total revenues from continuing operations for the year ended December 31, 2008 were $108.8 million, a $12.6 million increase compared to the year ended December 31, 2007. This increase was due to revenues attributable to our crude pipeline assets acquired in the first quarter of 2008, an increase in affiliate refined product shipments and the effect of annual tariff increases. These increases were partially offset by a decrease in third-party shipments, a decrease in shipments on our intermediate pipeline system and a net decrease in previously deferred revenue realized. Also affecting our revenue comparison was 2007 third quarter revenue of $2.7 million related to our sale of inventory of accumulated overages of refined products at our terminals. There was no comparable revenue for the year ended December 31, 2008.

Revenues from our refined product pipelines were $59.8 million, a decrease of $3.6 million compared to the year ended December 31, 2007. This decrease was due to a decline in third-party shipments as a result of reduced production and downtime following an explosion at Alon s Big Spring refinery during the first quarter of 2008 and a $0.5 million decrease in previously deferred revenue realized. These decreases were partially offset by an increase in affiliate shipments and the effect of the annual tariff increase on refined product shipments. Overall shipments on our refined product pipeline system decreased to an average of 106 mbpd compared to 124 mbpd for the year ended December 31, 2007.

Revenues from our intermediate pipelines were $11.9 million, a decrease of $1.8 million compared to the year ended December 31, 2007. This decrease was due to the effects of downtime at Holly s Navajo Refinery during the second quarter of 2008 and a $1.2 million decrease in previously deferred revenue realized. These decreases were partially offset by the effect of the annual tariff increase on intermediate pipeline shipments. Shipments on our intermediate product pipeline system decreased to an average of 58.9 mbpd compared to 65 mbpd for the year ended December 31, 2007.

Revenues from our crude pipelines were $22.4 million; shipments for the year ended December 31, 2008 averaged 111.4 mbpd.

Revenues from terminal, tankage and loading rack fees were $14.8 million, a decrease of $1.6 million compared to the year ended December 31, 2007. This decrease is due principally to the effects of downtime at Alon s Big Spring Refinery during the first nine months of 2008 and downtime at Holly s Navajo Refinery during the second quarter of 2008. Refined products terminalled in our facilities decreased to an average of 142.3 mbpd compared to 165.4 mbpd for year ended December 31, 2007.

Other revenues for the year ended December 31, 2007 consisted of $2.7 million related to the sale of inventory of accumulated terminal overages of refined product to Holly. There was no comparable revenue for the year ended December 31, 2008.

Operations Expense

Operations expense for the year ended December 31, 2008 increased by $8.5 million compared to the year ended December 31, 2007. This increase in expense was due principally to the commencement of our crude pipeline operations on March 1, 2008 and increased pipeline maintenance and payroll costs.

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Depreciation and Amortization

Depreciation and amortization for the year ended December 31, 2008 increased by $9 million compared to the year ended December 31, 2007. This increase was due to increased depreciation and amortization attributable to the crude pipelines, tankage assets and related transportation agreement acquired in February 2008.

General and Administrative

General and administrative costs for the year ended December 31, 2008 increased by $1.5 million compared to the year ended December 31, 2007, due principally to increased professional fees and equity based compensation expense.

Interest Expense

Interest expense for the year ended December 31, 2008 totaled $21.8 million, an increase of $8.5 million compared to the year ended December 31, 2007. This increase is due principally to interest attributable to advances from the Credit Agreement that were used to finance the purchase of the Crude Pipelines and Tankage Assets in the first quarter of 2008 as well as capital projects. For the year ended December 31, 2008, fair value adjustments to our interest rate swaps resulted in $2.3 million in non-cash interest expense. Excluding the effects of these fair value adjustments, our aggregate effective interest rate was 5.6% for the year ended December 31, 2008 compared to 7.2% for 2007.

State Income Tax

We recorded state income taxes of $270,000 and $200,000 for the years ended December 31, 2008 and 2007, respectively, that are solely attributable to the Texas margin tax.

Discontinued Operations

For the years ended December 31, 2008 and 2007, Rio Grande operations generated earnings of $5.9 million and $5.2 million, respectively. Rio Grande earnings for the years ended December 31, 2008 and 2007 are presented net of earnings attributable to noncontrolling interest holders of $1.3 million and $1.1 million, respectively.

LIQUIDITY AND CAPITAL RESOURCES

Overview

We have a $300 million senior secured revolving Credit Agreement expiring in August 2011. The Credit Agreement is available to fund capital expenditures, acquisitions, and working capital and for general partnership purposes. In addition, the Credit Agreement is available to fund letters of credit up to a $50 million sub-limit and to fund distributions to unitholders up to a $20 million sub-limit. During the year ended December 31, 2009, we received advances totaling $239 million that were used for our acquisitions and for capital projects and repaid $233 million, resulting in $6 million in net advances received. As of December 31, 2009, we had $206 million outstanding under the Credit Agreement.

There are currently a total of thirteen lenders under the Credit Agreement with individual commitments ranging from $15 million to $40 million. If any particular lender 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 these lenders in order to monitor their financial stability and assess their ongoing ability to honor their commitments under the Credit Agreement. We have not experienced, nor do we 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.

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Our Senior Notes maturing March 1, 2015 are registered with the SEC and bear interest at 6.25%. The Senior Notes are unsecured and impose certain restrictive covenants, 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.

In connection with our December 1, 2009 acquisition of Sinclair s Tulsa logistics assets, 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 price.

In November 2009, we closed on a public offering of 2,185,000 of our common units including 285,000 common units issued pursuant to the underwriters exercise of their over-allotment option. Aggregate net proceeds of $74.9 million were used to fund the cash portion of our December 1, 2009 asset acquisitions, to repay outstanding borrowings under the Credit Agreement and for general partnership purposes.

Additionally in May 2009, we closed a public offering of 2,192,400 of our common units including 192,400 common units issued pursuant to the underwriters exercise of their over-allotment option. Net proceeds of $58.4 million were used to repay outstanding borrowings under the Credit Agreement and for general partnership purposes.

Concurrently with the 2009 common unit issuances described above, we received aggregate capital contributions of $3.8 million from our general partner to maintain its 2% general partner interest.

As partial consideration for our purchase of the Crude Pipelines and Tankage Assets in 2008, we issued 217,497 of our common units having a value of $9 million to Holly. Also, Holly purchased an additional 2,503 of our common units for $0.1 million and HEP Logistics Holdings, L.P., our general partner, contributed $0.2 million as an additional capital contribution in order to maintain its 2% general partner interest.

Under our registration statement filed with the SEC using a shelf registration process, we currently have the ability to raise approximately $860 million through security offerings, through one or more prospectus supplements that would describe, among other things, the specific amounts, prices and terms of any securities offered and how the proceeds would be used. Any proceeds from the sale of securities would be used for general business purposes, which may include, among other things, funding acquisitions of assets or businesses, working capital, capital expenditures, investments in subsidiaries, the retirement of existing debt and/or the repurchase of common units or other securities.

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

In February, May, August and November 2009, we paid regular quarterly cash distributions of $0.765, $0.775, $0.785 and $0.795, respectively, on all units, an aggregate amount of $61.2 million. Included in these distributions was $5.5 million paid to the general partner as an incentive distribution.

Cash flows from continuing and discontinued operations have been combined for presentation purposes in the Consolidated Statements of Cash Flows. For the years ended December 31, 2009, 2008 and 2007, net cash flows from our discontinued Rio Grande operations were $37.6 million, $3.5 million and $3.7 million, respectively. Net cash flows from discontinued operations for 2009 includes $35 million in proceeds received upon the sale of our Rio Grande interest. As we have reinvested these proceeds into the Roadrunner and Beeson Pipelines, we do not believe that the absence of cash flows attributable to Rio Grande s operations will have a significant effect on our future liquidity or cash flows. With respect to the Roadrunner Pipeline, we entered into the 15-year Holly RPA, whereby Holly agreed to transport volumes of crude oil on our Roadrunner Pipeline that will result in minimum annual revenues to us of $9.2 million. We expect that cash flows generated from the Roadrunner Pipeline alone, will more than offset the absence of cash flows from Rio Grande.

Cash and cash equivalents decreased by $2.8 million during the year ended December 31, 2009. The cash flows used for investing activities of $147.4 million, exceeded cash flows provided by operating and financing activities of $68.2 million and $76.4 million, respectively. Working capital increased by $42.2 million due principally to the reclassification of $29 million in Credit Agreement advances to long-term debt and a decrease in deferred revenue. These advances were classified as short-term borrowings at December 31, 2008 and have been reclassified to long-term debt since the Credit Agreement expires in 2011.

Cash Flows Operating Activities

Year Ended December 31, 2009 Compared with Year Ended December 31, 2008

Cash flows from operating activities increased by $4.5 million from $63.7 million for the year ended December 31, 2008 to $68.2 million for the year ended December 31, 2009. This increase is due principally to $12.4 million in additional cash collections from our major customers, resulting principally from increased revenues, partially offset by year-over-year changes in payments attributable to increased operations.

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. For the year ended December 31, 2009, we received cash payments of $8.6 million under these commitments. We billed $15.7 million during the year ended December 31, 2008 related to shortfalls that subsequently expired without recapture and was recognized as revenue during the year ended December 31, 2009. Another $2.7 million is included in our accounts receivable at December 31, 2009 related to shortfalls that occurred in the fourth quarter of 2009.

Year Ended December 31, 2008 Compared with Year Ended December 31, 2007

Cash flows from operating activities increased by $4.6 million from $59.1 million for the year ended December 31, 2007 to $63.7 million for the year ended December 31, 2008. This increase is due principally to $20.8 million in additional cash collections from our major customers, resulting principally from increased revenues and shortfall billings, partially offset by miscellaneous year-over-year changes in collections and payments.

For the year ended December 31, 2008, we received cash payments of $14.3 million related to shortfall billings under these commitments. We billed $3.8 million during the year ended December 31, 2007 related to shortfalls that occurred in this period that expired without recapture and was recognized as revenue during the year ended December 31, 2008. Another $1.8 million is included in our accounts receivable at December 31, 2008 related to shortfalls that occurred in the fourth quarter of 2008.

Cash Flows Investing Activities

Year Ended December 31, 2009 Compared with Year Ended December 31, 2008

Cash flows used for investing activities decreased by $65.9 million from $213.3 million for the year ended December 31, 2008 to $147.4 million for the year ended December 31, 2009. During the year ended December 31, 2009, we paid $95.1 million with respect to our asset acquisitions from Holly, consisting of a 16-inch intermediate pipeline, loading rack facilities in Tulsa, Oklahoma and the Roadrunner and Beeson Pipelines. We also paid $25.7 million in cash upon our purchase of the logistics and storage assets from Sinclair and purchased our 25% joint venture interest in the SLC Pipeline for $25.5 million. Additionally, additions to properties and equipment for the year ended December 31, 2009 were $33 million compared to $42.3 million for same period last year. These additions relate principally to the expansion of our pipeline system between Artesia, New Mexico and El Paso, Texas, the South System. 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. For the year ended December 31, 2008, we paid $171 million in connection with our purchase of the Crude Pipelines and Tankage Assets from Holly in February 2008.

Year Ended December 31, 2008 Compared with Year Ended December 31, 2007
Cash flows used for investing activities increased by $203.7 million from $9.6 million for the year ended December 31, 2007 to $213.3 million for the year ended December 31, 2008. In connection with our purchase of the Crude Pipelines and Tankage Assets on February 29, 2008, we paid cash consideration to Holly of $171 million. Additions to properties and equipment for the year ended December 31, 2008 was $42.3 million, an increase of $32.3 million from $10 million for the year ended December 31, 2007.

Cash Flows Financing Activities

Year Ended December 31, 2009 Compared with Year Ended December 31, 2008
Cash flows provided by financing activities decreased by $68.1 million from $144.6 million for the year ended December 31, 2008 to $76.4 million for the ended December 31, 2009. During the year ended December 31, 2009, we received $239 million and repaid $233 million in advances under the Credit Agreement. We also 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 Holly s transferred basis in the assets acquired from Holly 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 restricted unit incentive grants. During the year ended December 31, 2008, we received net advances of $200 million under the Credit Agreement of which $171 million was used to finance the cash portion of the consideration paid to acquire the Crude Pipelines and Tankage Assets. During the year ended December 31, 2008, we paid $52.4 million in distributions on all units including the general partner interest and paid $1.8 million in distributions to noncontrolling interest holders in Rio Grande. Additionally in 2008, we paid $0.8 million for the purchase of our common units for restricted unit grants and paid $0.7 million in deferred financing costs that were attributable to the amendment to our Credit Agreement.

Year Ended December 31, 2008 Compared with Year Ended December 31, 2007
Cash flows provided by financing activities increased by $195.3 million from $50.7 million used for financing activities for the year ended December 31, 2007 to $144.6 million provided by financing activities for the ended December 31, 2008. During the year ended December 31, 2008, we received net advances of $200 million under the Credit Agreement of which $171 million was used to finance the cash portion of the consideration paid to acquire the Crude Pipelines and Tankage Assets. During the year ended December 31, 2008, we paid cash distributions on all units and the general partner interest in the aggregate amount of $52.4 million, an increase of $4.4 million from $48 million for the year ended December 31, 2007. Cash distributions paid to noncontrolling interest holders in Rio Grande were $1.8 million for the year ended December 31, 2008, an increase of $0.5 million from $1.3 million for the year ended December 31, 2007. Cash paid for the purchase of our common units for restricted grants was $0.8 million for the year ended December 31, 2008, a decrease of $0.3 million from $1.1 million for the year ended December 31, 2007. Also for the year ended December 31, 2008, we paid $0.7 million in deferred financing costs that were attributable to the amendment to our Credit Agreement.

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 2010 capital budget is comprised of $4.8 million for maintenance capital expenditures and $6 million for expansion capital expenditures.

We have an option agreement with Holly, granting us an option to purchase Holly s 75% equity interests in the UNEV Pipeline, a joint venture pipeline currently under construction that will be capable of transporting refined petroleum products from Salt Lake City, Utah to Las Vegas, Nevada. Under this agreement, we have an option to purchase Holly s equity interests in the UNEV Pipeline, effective for a 180-day period commencing when the UNEV Pipeline becomes operational, at a purchase price equal to Holly s investment in the joint venture pipeline, plus interest at 7% per annum. The initial capacity of the pipeline will be 62,000 bpd, with the capacity for further expansion to 120,000 bpd. The total cost of the pipeline project including terminals is expected to be $275 million.

Holly currently anticipates that all requisite regulatory approvals required to commence the construction of the pipeline will be received by the start of the second quarter of 2010. Once such approvals are received, construction of the pipeline will take approximately nine months. Under this schedule, the pipeline would become operational during the first quarter of 2011.

We expect that our currently planned expenditures for sustaining and maintenance capital as well as expenditures for acquisitions and capital development projects such as the UNEV Pipeline described above, will be funded with existing cash generated by operations, the sale of additional limited partner units, the issuance of debt securities and advances under our $300 million Credit Agreement maturing August 2011, or a combination thereof. With volatility and uncertainty in the current 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 current debt and equity markets, we may not be able to issue new debt and equity securities at acceptable pricing. Without additional capital beyond amounts available under the Credit Agreement, our ability to fund some of these capital projects may be limited, especially the UNEV Pipeline.

We are not obligated to purchase these assets nor are we subject to any fees or penalties if HLS board of directors decide not to proceed with any of these opportunities.

Credit Agreement

We have a $300 million senior secured revolving Credit Agreement expiring in August 2011. The Credit Agreement is available to fund capital expenditures, acquisitions, and working capital and for general partnership purposes. In addition, the Credit Agreement is available to fund letters of credit up to a $50 million sub-limit and to fund distributions to unitholders up to a $20 million sub-limit. Advances under the Credit Agreement that are designated for working capital are classified as short-term liabilities. Other advances under the Credit Agreement, including advances used for the interim financing of capital projects, are classified as long-term liabilities. During the year ended December 31, 2009, we received advances totaling $239 million that were used as interim financing for our acquisitions and for capital projects and repaid $233 million, resulting in $6 million in net advances received. As of December 31, 2009, we had $206 million outstanding under the Credit Agreement.

Our obligations under the Credit Agreement are collateralized by substantially all of our assets. Indebtedness under the Credit Agreement is recourse to HEP Logistics Holdings, L.P., our general partner, and guaranteed by our wholly-owned subsidiaries. Any recourse to HEP Logistics Holdings, L.P. 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. We are required to reduce all working capital borrowings under the Credit Agreement to zero for a period of at least 15 consecutive days in each twelve-month period prior to the maturity date of the agreement. As of December 31, 2009, we had no working capital borrowings.

Indebtedness under the Credit Agreement bears interest, at our option, at either (a) the reference rate as announced by the administrative agent plus an applicable margin (ranging from 0.25% to 1.50%) or (b) at a rate equal to the London Interbank Offered Rate (LIBOR) plus an applicable margin (ranging from 1.00% to 2.50%). In each case, the applicable margin is based upon the ratio of our funded debt (as defined in the agreement) to EBITDA (earnings before interest, taxes, depreciation and amortization, as defined in the agreement). At December 31, 2009, we were subject to an applicable margin of 1.75%. We incur a commitment fee on the unused portion of the Credit Agreement at a rate ranging from 0.20% to 0.50% based upon the ratio of our funded debt to EBITDA for the four most recently completed fiscal quarters. At December 31, 2009, we are subject to a 0.30% commitment fee on the $94 million unused portion of the Credit Agreement. The agreement expires in August 2011. At that time, the agreement will terminate and all outstanding amounts thereunder will become due and payable.

The 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 and 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.

Additionally, the Credit Agreement contains certain provisions whereby the lenders may accelerate payment of outstanding debt under certain circumstances.

Senior Notes Due 2015

Our Senior Notes maturing March 1, 2015 are registered with the SEC and bear interest at 6.25%. 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 Holdings, L.P., our general partner, and guaranteed by our wholly-owned subsidiaries. However, any recourse to HEP Logistics Holdings, L.P. would be limited to the extent of its assets, which other than its investment in us, are not significant.

Our contribution agreements with Alon and our purchase and contribution agreements with Holly with respect to the Intermediate Pipelines and the Crude Pipelines and Tankage Assets restrict us from selling pipelines and terminals acquired from Alon or Holly, as applicable, and from prepaying more than $30 million of the Senior Notes until 2015 and $171 million in borrowings for the purchase of the Crude Pipelines and Tankage Assets until 2018, subject to certain limited exceptions.

Long-term Debt

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

	December 31,	
	2009	**2008**
	(In thousands)	
Credit Agreement	$ 206,000	$ 200,000
Senior Notes		
Principal	185,000	185,000
Unamortized discount	(1,964)	(2,344)
Unamortized premium dedesignated fair value hedge	1,791	2,137
	184,827	184,793
Total debt	390,827	384,793
Less short-term borrowings under credit agreement		29,000
Total long-term debt	$ 390,827	$ 355,793

Our interest rate swap contracts are discussed under Risk Management.

Long-term Contractual Obligations

The following table presents our long-term contractual obligations as of December 31, 2009.

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	Over 5 Years
			(In thousands)		
Long-term debt principal	$ 391,000	$	$ 206,000	$	$ 185,000
Long-term debt interest	71,415	15,643	26,866	23,125	5,781
Pipeline operating lease	45,386	6,051	12,103	12,103	15,129
Right-of-way leases	2,260	213	413	348	1,286
Other	7,626	837	1,149	960	4,680
Total	$ 517,687	$ 22,744	$ 246,531	$ 36,536	$ 211,876

Our long-term debt consists of the $185 million principal balance of our Senior Notes and $206 million of outstanding principal under our Credit Agreement.

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 below include only obligations under the remaining non-cancelable terms of these agreements at December 31, 2009. 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.

Impact of Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2009, 2008 and 2007.

A substantial majority of our revenues are generated under long-term contracts that include the right to increase our rates and minimum revenue guarantees annually for increases in the PPI. Historically, the PPI has increased an average of 3.1% annually over the past 5 calendar years. With respect to our 15-year transportation agreement with Alon, the 2009 annual PPI adjustment resulted in a minor tariff rate decrease; the 2010 annual PPI adjustment will result in a tariff rate increase.

Environmental Matters

Our operation of pipelines, terminals, and associated facilities in connection with the storage and transportation 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.

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Under the Third Restated Omnibus Agreement, Holly agreed to indemnify us up to certain aggregate amounts for any environmental noncompliance and remediation liabilities associated with assets transferred to us and occurring or existing prior to the date of such transfers. The transfers that are covered by the agreement include the refined product pipelines, terminals and tanks transferred by Holly s subsidiaries in connection with our initial public offering in July 2004, the intermediate pipelines acquired in July 2005, and the Crude Pipelines and Tankage Assets acquired in 2008. The Third Restated Omnibus Agreement provides environmental indemnification of up to $15 million for the assets transferred to us, other than the Crude Pipelines and Tankage Assets, plus an additional $2.5 million for the intermediate pipelines acquired in July 2005. Except as described below, Holly s indemnification obligations described above will remain in effect for an asset for ten years following the date it is transferred to us. The Third Restated Omnibus Agreement also provides an additional $7.5 million of indemnification through 2023 for environmental noncompliance and remediation liabilities specific to the Crude Pipelines and Tankage Assets. Holly s indemnification obligations described above do not apply to our 2009 acquisitions consisting of (i) the Tulsa loading racks acquired from Holly, (ii) the 16-inch intermediate pipeline, (iii) the Roadrunner Pipeline, (iv) the Beeson Pipeline, or (v) the logistics and storage assets acquired from Sinclair.

Under provisions of the Holly ETA and Holly PTTA, Holly will indemnify us for environmental liabilities arising from our pre-ownership operations of the Tulsa loading racks acquired from Holly in August 2009 and the Tulsa logistics and storage assets acquired from Sinclair in December 2009. Additionally, Holly agreed to indemnify us for any liabilities arising from Holly s operation of the loading racks under the Holly ETA.

Additionally, 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 Holly. Certain of these projects were underway prior to our purchase and represent liabilities of Holly Corporation as the obligation for future remediation activities was retained by Holly. As of December 31, 2009, we have an accrual of $0.2 million that relates to two environmental clean-up projects. The remaining projects, including assessment and monitoring activities, are covered under the Holly environmental indemnification discussed above and represent liabilities of Holly Corporation.

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 will recognize shortfall billings as revenue prior to the expiration of the contractual term period to provide services only when we determine with a high likelihood that we will not be required to provide services within the allowed period. We determine this 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.

Long-Lived Assets

We calculate depreciation and amortization based on estimated useful lives and salvage values of our assets. When assets are placed into service, we make estimates with respect to their useful lives that we believe are reasonable. However, factors such as competition, regulation or environmental matters could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization. We evaluate long-lived 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. Estimates of future discounted cash flows and fair value of assets require subjective assumptions with regard to future operating results, and actual results could differ from those estimates.

We have evaluated our transportation agreements for impairment as of December 31, 2009 and determined that projected cash flows to be received under these agreements substantially exceed our carrying balances. Furthermore, there were no impairments of our long-lived assets during the years ended December 31, 2009, 2008 and 2007.

Contingencies

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

RISK MANAGEMENT

We use interest rate swaps (derivative instruments) to manage our exposure to interest rate risk. As of December 31, 2009, we have three interest rate swap contracts.

We have an interest rate swap that hedges our exposure to the cash flow risk caused by the effects of LIBOR changes on the $171 million Credit Agreement advance that we used to finance our purchase of the Crude Pipelines and Tankage Assets from Holly in February 2008. This interest rate swap effectively converts our $171 million LIBOR based debt to fixed rate debt having an interest rate of 3.74% plus an applicable margin, currently 1.75%, which equaled an effective interest rate of 5.49% as of December 31, 2009. The maturity date of this swap contract is February 28, 2013.

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 our $171 million 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 income. 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 our $171 million variable rate debt. Any ineffectiveness is reclassified from accumulated other comprehensive income to interest expense. As of December 31, 2009, we had no ineffectiveness on our cash flow hedge.

We also have an interest rate swap contract that effectively converts interest expense associated with $60 million of our 6.25% Senior Notes from a fixed to a variable rate(Variable Rate Swap). Under this swap contract, interest on the $60 million notional amount is computed using the three-month LIBOR plus a spread of 1.1575%, which equaled an effective interest rate of 1.41% as of December 31, 2009. The maturity date of this swap contract is March 1, 2015, matching the maturity of the Senior Notes.

We entered into an additional interest rate swap contract effective December 1, 2008, that effectively unwinds the effects of the Variable Rate Swap discussed above, converting $60 million of our hedged long-term debt back to fixed rate debt (Fixed Rate Swap). Under the Fixed Rate Swap, interest on a notional amount of $60 million is computed at a fixed rate of 3.59% versus three-month LIBOR which when added to the 1.1575% spread on the Variable Rate Swap results in an effective fixed interest rate of 4.75%. The maturity date of this swap contract is December 1, 2013.

Prior to the execution of our Fixed Rate Swap, the Variable Rate Swap was designated as a fair value hedge of $60 million in outstanding principal under the Senior Notes. We dedesignated this hedge in October 2008. At that time, the carrying balance of our Senior Notes included a $2.2 million premium due to the application of hedge accounting until the dedesignation date. This premium is being amortized as a reduction to interest expense over the remaining term of the Variable Rate Swap.

Our interest rate swaps not having a hedge designation are measured quarterly at fair value either as an asset or a liability in our Consolidated Balance Sheets with the offsetting fair value adjustment to interest expense. For the years ended December 31, 2009 and 2008, we recognized $0.2 million and $2.3 million, respectively, in interest expense attributable to fair value adjustments to our interest rate swaps.

We record interest expense equal to the variable rate payments under the swaps. Receipts under the swap agreements are recorded as a reduction of interest expense.

Additional information on our interest rate swaps is as follows:

Interest Rate Swaps	Balance Sheet Location	Fair Value	Location of Offsetting Balance	Offsetting Amount
			(In thousands)	
Asset				
Fixed-to-variable interest rate swap $60 million of 6.25% Senior Notes	Other assets	$ 2,294	Long-term debt	$ (1,791)(1)
			HEP partners equity	(1,942)(2)
			Interest expense	1,439(3)
		$ 2,294		$ (2,294)
Liability				
Cash flow hedge $171 million LIBOR based debt	Other long-term liabilities	$ (9,141)	Accumulated other comprehensive loss	$ 9,141
Variable-to-fixed interest rate swap $60 million	Other long-term liabilities	(2,555)	HEP partners equity	4,166(2)
			Interest expense	(1,611)
		$ (11,696)		$ 11,696

(1) Represents unamortized balance of

dedesignated hedge premium.

(2) Represents prior year charges to interest expense.

(3) Net of amortization of premium attributable to dedesignated hedge.

On January 29, 2010, we received notice from the counterparty that it is exercising its option to cancel the Variable Rate Swap on March 1, 2010, pursuant to the terms of the swap contract. We will receive a cancellation premium of $1.9 million.

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

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

At December 31, 2009, we had an outstanding principal balance on our 6.25% Senior Notes of $185 million. By means of our interest rate swap contracts, we have effectively converted the 6.25% fixed rate on $60 million of the Senior Notes to a fixed rate of 4.75%. A change in interest rates would generally affect the fair value of the debt, but not our earnings or cash flows. At December 31, 2009, the fair value of our Senior Notes was $177.6 million. We estimate a hypothetical 10% change in the yield-to-maturity applicable to the Senior Notes at December 31, 2009 would result in a change of approximately $5.5 million in the fair value of the debt.

For the variable rate Credit Agreement, changes in interest rates would affect cash flows, but not the fair value. At December 31, 2009, outstanding principal under the Credit Agreement was $206 million. By means of our cash flow hedge, we have effectively converted the variable rate on $171 million of outstanding principal to a fixed rate of 5.49%. For the unhedged $35 million portion, a hypothetical 10% change in interest rates applicable to the Credit Agreement would not materially affect our cash flows.

At December 31, 2009, 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 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, 2009 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 believes that, as of December 31, 2009, the Partnership maintained effective internal control over financial reporting.

The Partnership acquired certain logistics and storage assets from an affiliate of Sinclair Oil Company on December 1, 2009. Management has excluded the operations of these facilities from its assessment of the effectiveness of our internal control over financial reporting as of December 31, 2009. The carrying amount of these facilities represents 5% and 16% of our total and net assets, respectively, as of December 31, 2009. We plan to fully integrate the operations of these facilities into our assessment of the effectiveness of internal control over financial reporting in 2010.

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, 2009. That report appears on page 67.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited Holly Energy Partners, L.P. s (the Partnership) internal control over financial reporting as of December 31 2009, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Partnership 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. Our responsibility is to express an opinion on the effectiveness of 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.

As indicated in the accompanying, Management s Report on its Assessment of the Partnership s Internal Control Over Financial Reporting, management s assessment of, and conclusion on, the effectiveness of internal controls over financial reporting did not include internal controls of the certain logistics and storage assets acquired from an affiliate of Sinclair Oil Company which are included in the December 31, 2009 consolidated financial statements of Holly Energy Partners, L.P. and represents 5% and 16% of total and net assets, respectively, as of December 31, 2009. Our audit of internal control over financial reporting of Holly Energy Partners, L.P. also did not include an evaluation of the internal control over financial reporting of the certain logistics and storage assets acquired.

In our opinion, Holly Energy Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, 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, 2009 and 2008, and the related consolidated statements of income, equity, and cash flows for each of the three years in the period ended December 31, 2009, our report dated February 16, 2010, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP
Dallas, Texas
February 16, 2010

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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, 2009 and 2008, and the related consolidated statements of income, equity, and cash flows for each of the three years in the period ended December 31, 2009. 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 also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Holly Energy Partners, L.P. at December 31, 2009 and 2008, and the related consolidated results of its operations and its cash flows, for each of the three years in the period ended December 31, 2009 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, 2009, 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 16, 2010 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP
Dallas, Texas
February 16, 2010

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Holly Energy Partners, L.P.
Consolidated Balance Sheets

	December 31, 2009	December 31, 2008
	(In thousands, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,508	$ 3,708
Accounts receivable:		
Trade	4,693	3,937
Affiliates	14,074	9,395
	18,767	13,332
Prepaid and other current assets	739	593
Current assets of discontinued operations	2,195	2,706
Total current assets	24,209	20,339
Properties and equipment, net	398,044	257,886
Transportation agreements, net	115,436	122,383
Goodwill	49,109	
Investment in SLC Pipeline	25,919	
Other assets	4,128	6,682
Non-current assets of discontinued operations		32,398
Total assets	$ 616,845	$ 439,688
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 3,860	$ 5,155
Affiliates	2,351	2,160
	6,211	7,315
Accrued interest	2,863	2,845
Deferred revenue	8,402	15,658
Accrued property taxes	1,072	1,015
Other current liabilities	1,257	1,403
Short-term borrowings under credit agreement		29,000
Current liabilities of discontinued operations		935
Total current liabilities	19,805	58,171
Long-term debt	390,827	355,793
Other long-term liabilities	12,349	17,604

Equity:		
Holly Energy Partners, L.P. partners equity (deficit):		
Common unitholders (21,141,009 and 8,390,000 units issued and outstanding at December 31, 2009 and 2008, respectively)	275,553	169,126
Subordinated unitholders (7,000,000 units issued and outstanding at December 31, 2008)		(85,059)
Class B subordinated unitholders (937,500 units issued and outstanding at December 31, 2009 and 2008)	21,426	21,455
General partner interest (2% interest)	(93,974)	(94,653)
Accumulated other comprehensive loss	(9,141)	(12,967)
Total Holly Energy Partners, L.P. partners equity (deficit)	193,864	(2,098)
Noncontrolling interest		10,218
Total equity	193,864	8,120
Total liabilities and equity	$ 616,845	$ 439,688

See accompanying notes.

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Holly Energy Partners, L.P.
Consolidated Statements of Income

	Years Ended December 31, 2009	2008	2007
	(In thousands, except per unit data)		
Revenues:			
Affiliates	$ 101,395	$ 85,040	$ 63,709
Third parties	45,166	23,782	32,481
	146,561	108,822	96,190
Operating costs and expenses:			
Operations	44,003	38,920	30,467
Depreciation and amortization	26,714	21,937	12,920
General and administrative	7,586	6,380	4,914
	78,303	67,237	48,301
Operating income	68,258	41,585	47,889
Other income (expense):			
Equity in earnings of SLC Pipeline	1,919		
SLC Pipeline acquisition costs	(2,500)		
Interest income	11	118	454
Interest expense	(21,501)	(21,763)	(13,289)
Gain on sale of assets		36	298
Other Income	67	990	
	(22,004)	(20,619)	(12,537)
Income from continuing operations before income taxes	46,254	20,966	35,352
State income tax	(20)	(270)	(200)
Income from continuing operations	46,234	20,696	35,152
Discontinued operations			
Income from discontinued operations, net of noncontrolling interest of $1,579, $1,278 and $1,067 for the years ended December 31, 2009, 2008 and 2007, respectively	5,301	4,671	4,119
Gain on sale of interest in Rio Grande Pipeline Company	14,479		
Income from discontinued operations	19,780	4,671	4,119

Net income		66,014		25,367		39,271
Less general partner interest in net income, including incentive distributions		7,947		3,913		3,166
Limited partners interest in net income	$	58,067	$	21,454	$	36,105
Limited partners per unit interest in earnings basic and diluted:						
Income from continuing operations	$	2.12	$	1.04	$	1.99
Income from discontinued operations		0.28		0.28		0.25
Gain on sale of discontinued operations		0.78				
Net income	$	3.18	$	1.32	$	2.24
Weighted average limited partners units outstanding		18,268		16,291		16,108

See accompanying notes.

Holly Energy Partners, L.P.
Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Cash flows from operating activities			
Net Income	$ 66,014	$ 25,367	$ 39,271
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization (includes discontinued operations)	27,597	22,889	14,382
SLC Pipeline earnings in excess of distributions	(419)		
Change in fair value interest rate swaps	175	2,282	
Noncontrolling interest in earnings of Rio Grande Pipeline Company	1,579	1,278	1,067
Amortization of restricted and performance units	699	1,688	1,375
Gain on sale of interest in Rio Grande Pipeline Company	(14,479)		
Gain on sale of assets		(36)	(298)
(Increase) decrease in current assets:			
Accounts receivable trade	388	1,529	728
Accounts receivable affiliates	(4,679)	(3,695)	16
Prepaid and other current assets	(146)	(47)	666
Increase (decrease) in current liabilities:			
Accounts payable trade	(1,956)	2,805	(770)
Accounts payable affiliates	149	(3,819)	3,823
Accrued interest	18	(151)	55
Deferred revenue	(7,256)	11,958	(1,786)
Accrued property taxes	(74)	(32)	309
Other current liabilities	(248)	678	(271)
Other, net	833	957	489
Net cash provided by operating activities	68,195	63,651	59,056
Cash flows from investing activities			
Additions to properties and equipment	(32,999)	(42,303)	(9,957)
Acquisitions of assets from Holly Corporation	(95,080)	(171,000)	
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		
Proceeds from sale of assets		36	325
Net cash used for investing activities	(147,379)	(213,267)	(9,632)
Cash flows from financing activities			
Borrowings under credit agreement	239,000	285,000	

Repayments under credit agreement		(233,000)		(85,000)		
Proceeds from issuance of common units		133,301		104		
Contribution from general partner		3,812		186		
Distributions to HEP unitholders		(61,188)		(52,426)		(47,974)
Net purchase price in excess of transferred basis in assets acquired from Holly Corporation		(3,120)				
Distributions to noncontrolling interest		(1,500)		(1,800)		(1,290)
Purchase of units for restricted grants		(616)		(795)		(1,082)
Cost of issuing common units		(266)				
Deferred financing costs				(705)		(296)
Other						(16)
Net cash provided by (used for) financing activities		76,423		144,564		(50,658)
Cash and cash equivalents						
Decrease for the year		(2,761)		(5,052)		(1,234)
Beginning of year		5,269		10,321		11,555
End of year	$	2,508	$	5,269(1)	$	10,321

(1) Includes $1,561 in cash classified as current assets of discontinued operations at December 31, 2008.

See accompanying notes.

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Holly Energy Partners, L.P.
Consolidated Statements of 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, 2006	$ 176,844	$ (70,022)	$ 23,469	$ (94,065)	$	$ 10,963	$ 47,189
Distributions HEP unitholders	(22,762)	(19,495)	(2,611)	(3,106)			(47,974)
Distributions noncontrolling interest						(1,290)	(1,290)
Purchase of units for restricted grants	(1,082)						(1,082)
Amortization of restricted and performance units	1,375						1,375
Net income	18,432	15,792	2,115	2,932		1,067	40,338
Balance December 31, 2007	172,807	(73,725)	22,973	(94,239)		10,740	38,556
Issuance of common units	9,104						9,104
Cost of issuing common units	(71)						(71)
Capital contribution				186			186
Distributions HEP unitholders	(24,788)	(20,720)	(2,775)	(4,143)			(52,426)
Distributions noncontrolling interest						(1,800)	(1,800)
Purchase of units for restricted grants	(795)						(795)
Amortization of restricted and performance units	1,688						1,688
Comprehensive income:							
Net income	11,181	9,386	1,257	3,543		1,278	26,645
Change in fair value cash flow hedge					(12,967)		(12,967)

Comprehensive income	11,181	9,386	1,257	3,543	(12,967)	1,278	13,678
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 HEP unitholders	(35,245)	(16,275)	(2,925)	(6,743)			(61,188)
Distributions noncontrolling interest						(1,500)	(1,500)
Net purchase price in excess of transferred basis in assets acquired from Holly Corporation				(3,120)			(3,120)
Purchase of units for restricted 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
Change in fair value of cash flow hedge					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

See accompanying notes.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2009

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 34% owned by Holly Corporation (Holly). 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 refer to HEP unless the context otherwise indicates.

We operate in one business segment the operation of petroleum product and crude oil pipelines and terminals, tankage and loading rack facilities.

One of Holly s wholly-owned subsidiaries owns a refinery in Artesia, New Mexico, which Holly operates in conjunction with crude, vacuum distillation and other facilities situated in Lovington, New Mexico (collectively, the Navajo Refinery). The Navajo Refinery produces high-value refined products such as gasoline, diesel fuel and jet fuel and serves markets in the southwestern United States and northern Mexico. We own and operate intermediate feedstock pipelines (the Intermediate Pipelines), that connect the New Mexico refining facilities. Our operations serving the Navajo Refinery include refined product pipelines that serve as part of the refinery s product distribution network. We also own and operate crude oil pipelines and on-site crude oil tankage that supply and support the refinery. Our terminal operations serving the Navajo Refinery include an on-site truck rack at the refinery and five integrated refined product terminals located in New Mexico, Texas and Arizona.

Another of Holly s wholly-owned subsidiaries owns a refinery located near Salt Lake City, Utah (the Woods Cross Refinery). Our operations serving the Woods Cross Refinery include crude oil and refined product pipelines, crude oil tankage and a truck rack at the refinery, a refined product terminal in Spokane, Washington and a 50% non-operating interest in product terminals in Boise and Burley, Idaho.

In June 2009, Holly acquired a petroleum refinery, including supporting infrastructure, located in Tulsa, Oklahoma. In December 2009, Holly acquired an additional petroleum refinery, also in Tulsa, Oklahoma and located approximately two miles from its existing Tulsa refinery facility. Holly operates the facilities as one, integrated, highly complex facility (the Tulsa Refinery) that produces high-value refined products and serves markets primarily in the Mid-Continent region of the United States. Under two separate transactions, we acquired certain logistics assets that support the Tulsa Refinery (see Note 3) that primarily consist of truck and rail loading/unloading facilities, on-site refined product tankage and truck racks.

We also own and operate refined product pipelines and terminals, located primarily in Texas, that service Alon USA, Inc. s (Alon) refinery in Big Spring, Texas.

In March 2009, we acquired a 25% joint venture interest in a new 95-mile intrastate crude oil pipeline system (the SLC Pipeline) that we jointly own with Plains All American Pipeline, L.P. (Plains) that serves refineries in the Salt Lake City area (see Note 3).

On December 1, 2009, we sold our 70% interest in the Rio Grande Pipeline Company (Rio Grande) to a subsidiary of Enterprise Products Partners LP for $35 million. Accordingly, the results of operations of Rio Grande and the gain on the sale are presented in discontinued operations (see Note 2).

Principles of Consolidation

The consolidated financial statements include our accounts and those of our subsidiaries. All significant inter-company transactions and balances have been eliminated. The pipeline and terminal assets that Holly contributed to us concurrently with the completion of our initial public offering in 2004, the intermediate pipeline assets purchased from Holly in July 2005 and the various pipeline and logistic asset purchases from Holly in 2009 (see Note 3) were accounted for as transactions among entities under common control. Accordingly, these assets were recorded on our balance sheets at Holly s book basis instead of our purchase price or fair value.

If these assets had been acquired from third parties, our acquisition cost in excess of Holly s basis in the transferred assets of $160.4 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.

These consolidated financial statements reflect management s evaluation of subsequent events through the time of our filing of this annual report on Form 10-K on February 16, 2010.

Cash and Cash Equivalents

For purposes of the statements of cash flows, we consider all highly liquid investments with maturity of three months or less at the time of purchase to be cash equivalents. The carrying amounts reported on the balance sheet 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 Holly, 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. Depreciation is provided by the straight-line method over the estimated useful lives of the assets; primarily 10 to 16 years for terminal facilities, 23 to 33 years for pipelines and 3 to 10 years for corporate and other assets. Maintenance, repairs and major replacements are generally expensed as incurred. Costs of replacements constituting improvement are capitalized.

Transportation Agreements

The transportation agreement assets are stated at cost and are being amortized over the periods of the agreements using the straight-line method.

Goodwill

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. See Sinclair Logistics and Storage Assets Transaction under Note 3 for information on our goodwill acquired in 2009.

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Long-Lived Assets

We evaluate long-lived assets, including 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.

We have evaluated our transportation agreements for impairment as of December 31, 2009 and determined that projected cash flows to be received under these agreements substantially exceed our carrying balances. Furthermore, there were no impairments of our long-lived assets, including goodwill, during the years ended December 31, 2009, 2008 and 2007.

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, 2009, our underlying equity in the SLC Pipeline was $63 million compared to our recorded investment balance of $25.9 million, a difference of $37.1 million. This is attributable to the difference between our contributed capital and our allocated equity at formation of the SLC Pipeline. 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 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. If a reasonable estimate cannot be made at the time the liability is incurred, we record the liability when sufficient information is available to estimate the liability s fair value.

We have asset retirement obligations with respect to certain of our assets due to legal obligations to clean and/or dispose of various component parts at the time they are retired. At December 31, 2009, an asset retirement obligation of $0.6 million is included in Other long-term liabilities in our consolidated balance sheets.

Noncontrolling Interest

Accounting standards became effective January 1, 2009 that change the classification of noncontrolling interests, also referred to as minority interests, in the consolidated financial statements. As a result, all previous references to minority interest within these financial statements have been replaced with noncontrolling interest. Additionally, equity attributable to noncontrolling interests is now presented as a separate component of total equity in our consolidated financial statements. All amounts containing references to noncontrolling interests in these financial statements represent amounts attributable to noncontrolling interest holders of Rio Grande prior to our sale on December 1, 2009.

Revenue Recognition

Revenues are recognized as products are shipped through our pipelines and terminals. 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.

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We will recognize shortfall billings as revenue prior to the expiration of the contractual term period to provide services only when we determine with a high likelihood that we will not be required to provide services within the allowed period. We determine this 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.

Additional pipeline transportation revenues result from 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 arrangements or other sources are included in other assets to the extent such recoveries are considered probable. At December 31, 2009 and 2008, we had accruals for environmental remediation obligations of $0.2 million.

Income Tax

Effective January 1, 2007, the Texas margin tax applied to legal entities conducting business in Texas, including previously non-taxable entities such as limited partnerships and limited liability partnerships. The margin tax 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. Individual unitholders have different investment bases depending upon the timing and price of acquisition of their partnership units. Furthermore, each unitholder s tax accounting, which is partially dependent upon the unitholder s tax position, differs from the accounting followed in the consolidated financial statements. Accordingly, the aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each unitholder s tax attributes in our partnership is not available to us.

Net Income per Limited Partners Unit

We have identified the general partner interest and the subordinated units as participating securities and 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 Class B subordinated units) 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.

New accounting standards became effective January 1, 2009 that prescribe the application of the two-class method in computing earnings per unit to reflect a master limited partnership s contractual obligation to make distributions to the general partner, limited partners and incentive distribution rights holders. As a result, our quarterly earnings allocations to the general partner now include incentive distributions that were declared subsequent to quarter end. Prior to our adoption of these standards, our general partner earnings allocations included incentive distributions that were declared during each quarter. We have applied these standards on a retrospective basis. The application of these standards resulted in a decrease in our limited partners interest in net income of $0.02 for each of the years ended December 31, 2008 and 2007.

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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. Accordingly, results of operations of Rio Grande are presented in discontinued operations. Additionally, assets and liabilities attributable to Rio Grande have been reclassified as current assets, non-current assets and current liabilities of discontinued operations in our Consolidated Balance Sheet as of December 31, 2008.

In accounting for the sale, we recorded a gain of $14.5 million and a receivable of $2.2 million that represents our final distribution from Rio Grande. Our recorded net asset balance of Rio Grande at December 1, 2009, was $22.7 million, consisting of cash of $3.1 million, $29.9 million in properties and equipment, net and $10.3 million in equity, representing BP, Plc s 30% noncontrolling interest.

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 years ended December 31, 2009, 2008 and 2007, net cash flows from our discontinued Rio Grande operations were $37.6 million, $3.5 million and $3.7 million, respectively. Net cash flows from discontinued operations for 2009 includes $35 million in proceeds received upon the sale of our Rio Grande interest. We have reinvested these proceeds into the Roadrunner and Beeson Pipelines. With respect to the Roadrunner Pipeline, we entered into the 15-year Holly RPA, whereby Holly agreed to transport volumes of crude oil on our Roadrunner Pipeline that will result in minimum annual revenues to us of $9.2 million.

Note 3: Acquisitions

2009 Acquisitions

Sinclair Logistics and Storage Assets Transaction

On December 1, 2009, we acquired certain logistics and storage assets from an affiliate of Sinclair Oil Company (Sinclair) for $79.2 million consisting of storage tanks having approximately 1.4 million barrels of storage capacity and loading racks at Sinclair s refinery located in Tulsa, Oklahoma. 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, Holly, also a party to the transaction acquired Sinclair s Tulsa refinery.

Concurrent with this transaction, we entered into a 15-year pipeline, tankage and loading rack throughput agreement with Holly (the Holly PTTA), whereby Holly agreed to transport, throughput and load volumes of product via our Tulsa logistics and storage assets that will result in minimum annual revenues to us of $13.8 million.

In accounting for 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 management s preliminary fair value estimates based on a cost approach methodology.

Roadrunner / Beeson Pipelines Transaction

Also on December 1, 2009, we acquired from Holly 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 (the Centurion Pipeline) 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).

The Roadrunner Pipeline provides the Navajo Refinery with direct access to a wide variety of crude oils available at Cushing, Oklahoma. In connection with this transaction, we entered into a 15-year pipeline agreement with Holly (the Holly RPA), whereby Holly agreed to transport volumes of crude oil on our Roadrunner Pipeline that will result in minimum annual revenues to us of $9.2 million.

The Beeson Pipeline connects our New Mexico crude oil gathering system to the Navajo Refinery Lovington facility. It operates as a component of our crude pipeline system and provides Holly with added flexibility to move crude oil from our crude oil gathering systems.

Tulsa Loading Racks Transaction

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

In connection with this transaction, we entered into a 15-year equipment and throughput agreement with Holly (the Holly ETA), whereby Holly agreed to throughput a minimum volume of products via the acquired loading racks that will initially result in minimum annual revenues to us of $2.7 million.

Lovington-Artesia Pipeline Transaction

On June 1, 2009, we acquired from Holly 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. This pipeline was placed in service effective June 1, 2009 and operates as a component of our Intermediate Pipeline system that services Holly s Navajo Refinery.

In connection with this transaction, Holly agreed to amend our transportation agreement that relates to the Intermediate Pipelines acquired in 2005 (the Holly IPA). As a result, the term of the Holly IPA was extended by an additional 4 years and now expires in June 2024. Additionally, Holly s minimum commitment under the Holly IPA was increased and the Holly IPA currently results in minimum annual payments to us of $20.7 million.

We are a controlled subsidiary of Holly. In accounting for our 2009 acquisitions from Holly, consisting of the Roadrunner and Beeson Pipelines, loading rack facilities and 16-inch intermediate pipeline as discussed above, we recorded total property and equipment of $95.1 million representing Holly s cost basis of the transferred assets. Since we acquired the assets for $98.2 million, the $3.1 million aggregate purchase price in excess of Holly s transferred 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 Plains. The SLC Pipeline commenced operations effective March 2009 and allows various refiners in the Salt Lake City area, including Holly s Woods Cross Refinery, to ship crude oil into the Salt Lake City area from the Utah terminus of the Frontier Pipeline as well as crude oil flowing from Wyoming and Utah via Plains Rocky Mountain Pipeline. 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 Holly that was expensed as acquisition costs.

2008 Acquisition

Crude Pipelines and Tankage Transaction

On February 29, 2008, we acquired from Holly certain crude pipeline and tankage assets (the Crude Pipelines and Tankage Assets) for $180 million that consist of crude oil trunk lines that deliver crude oil to Holly s Navajo Refinery in southeast New Mexico, gathering and connection pipelines located in west Texas and New Mexico, on-site crude tankage located within the Navajo and Woods Cross Refinery complexes, a jet fuel products pipeline between Artesia and Roswell, New Mexico, a leased jet fuel terminal in Roswell, New Mexico and crude oil and product pipelines that support Holly s Woods Cross Refinery. The consideration paid consisted of $171 million in cash and 217,497 of our common units having a fair value of $9 million. We financed the $171 million cash portion of the consideration through borrowings under our senior secured revolving credit agreement expiring August 2011.

In connection with this transaction, we entered into the 15-year Holly CPTA. Under the Holly CPTA, Holly agreed to transport and store volumes of crude oil on the crude pipelines and tankage facilities that result in minimum annual payments to us.

See Note 11 for additional information on our long-term transportation agreements with Holly.

Note 4: Financial Instruments

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, debt and interest rate swaps. The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the short-tem maturity of these instruments.

Our debt consists of outstanding principal under our revolving credit agreement (the Credit Agreement) and our 6.25% senior notes (the Senior Notes). The $206 million carrying amount of outstanding debt under the Credit Agreement approximates fair value as interest rates are reset frequently using current rates. The estimated fair value of our Senior Notes was $177.6 million at December 31, 2009. This fair value estimate is based on market quotes provided from a third-party bank. See Note 8 for additional information on these 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.

We have interest rate swaps that are measured at fair value on a recurring basis using Level 2 inputs. With respect to these instruments, 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 agreements. Our measurements are 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 swaps, including fair value measurements.

Note 5: Properties and Equipment

	December 31,	
	2009	**2008**
	(In thousands)	
Pipelines and terminals	$ 455,075	$ 268,745
Land and right of way	25,230	17,677
Other	12,528	11,385
Construction in progress	10,484	38,589
	503,317	336,396
Less accumulated depreciation	105,273	78,510
	$ 398,044	$ 257,886

During each of the years ended December 31, 2009 and 2008 we capitalized $1 million in interest related to major construction projects. We did not capitalize any interest prior to 2008.

Depreciation expense was $19.7 million, $15.8 million and $10.9 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Note 6: Transportation Agreements

Our transportation agreements consist of the following:

The Alon transportation agreement represents a portion of the total purchase price of the Alon assets that was allocated based on an estimated fair value derived under an income approach. This asset is being amortized over 30 years ending 2035, the 15-year initial term of the Alon PTA plus the expected 15-year extension period.

The Holly crude pipelines and tankage agreement represents a portion of the total purchase price of the Crude Pipelines and Tankage Assets that was allocated using a fair value based on the agreement s expected contribution to our future earnings under an income approach. This asset is being amortized over 15 years ending 2023, the 15-year term of the Holly CPTA.

The carrying amounts of the transportation agreements are as follows:

	December 31, 2009	December 31, 2008
	(In thousands)	
Alon transportation agreement	$ 59,933	$ 59,933
Holly crude pipelines and tankage agreement	74,231	74,231
	134,164	134,164
Less accumulated amortization	18,728	11,781
	$ 115,436	$ 122,383

Amortization expense was $7 million, $6.1 million and $2 million for the years ended December 31, 2009, 2008 and 2007, respectively.

We have additional transportation agreements with Holly. One of the agreements relates to the pipelines and terminals contributed to us from Holly at the time of our initial public offering in 2004 (the Holly PTA). We also have the Holly IPA that relates to the Intermediate Pipelines acquired from Holly in 2005 and in June 2009. In 2009, we entered into the Holly ETA that relates to the Tulsa loading racks acquired from Holly in August 2009 and the Holly PTA that relates to the Roadrunner Pipeline acquired in December 2009. Our basis in the assets acquired under these transfers reflect Holly s historical cost and does not reflect a step-up in basis to fair value. Therefore, these agreements have a recorded value of zero.

In addition, we have the Holly PTTA under which we provide transportation and storage services to Holly via our Tulsa logistics and storage assets acquired from Sinclair. Since this agreement is with Holly and not between Sinclair and us, there is no purchase price allocation attributable to this agreement.

Note 7: Employees, Retirement and Incentive Plans

Employees who provide direct services to us are employed by Holly Logistic Services, L.L.C. (HLS), a Holly 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 Holly. These employees participate in the retirement and benefit plans of Holly. Our share of retirement and benefit plan costs was $2.8 million, $2.1 million and $1.3 million for the years ended December 31, 2009, 2008 and 2007, respectively. These amounts include retirement costs of $1.6 million, $1.1 million and $0.6 million for the years ended December 31, 2009, 2008 and 2007, respectively.

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We have adopted 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, 2009, we have two types of equity-based compensation, which are described below. The compensation cost charged against income for these plans was $1.2 million, $1.9 million and $1.3 million for the years ended December 31, 2009, 2008 and 2007, respectively. We currently purchase units in the open market instead of issuing new units for settlement of restricted unit grants. At December 31, 2009, 350,000 units were authorized to be granted under the equity-based compensation plans, of which 190,932 had not yet been 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 vesting for a certain key executive is contingent upon certain earnings per unit targets being realized. The fair value of each unit of restricted unit awards is measured at the market price as of the date of grant and is being amortized over the vesting period, including the units issued to the key executives, as we expect those units to fully vest.

A summary of restricted unit activity and changes during the year ended December 31, 2009 is presented below:

Restricted Units	**Grants**	**Weighted-Average Grant-Date Fair Value**	**Weighted-Average Remaining Contractual Term**	**Aggregate Intrinsic Value ($000)**
Outstanding at January 1, 2009 (not vested)	53,505	$ 41.28		
Granted	33,422	26.00		
Forfeited	(2,152)	42.53		
Vesting and transfer of full ownership to recipients	(31,504)	36.76		
Outstanding at December 31, 2009 (not vested)	53,271	$ 34.31	1.1 years	$ 2,122

The fair value of restricted units vested and transferred to recipients during the years ended December 31, 2009, 2008 and 2007 was $1.2 million, $0.8 million and $0.5 million, respectively. As of December 31, 2009, there was $0.4 million of total unrecognized compensation costs related to nonvested restricted unit grants. That cost is expected to be recognized over a weighted-average period of 1.1 years.

During the year ended December 31, 2009, we paid $0.6 million for the purchase of 26,431 of our common units in the open market for the recipients of our 2009 restricted unit grants.

Performance Units

Under our Long-Term Incentive Plan, we grant performance units to selected executives and employees who perform services for us. These performance units are payable based upon the growth in distributions on our common units during the requisite period, and generally vest over a period of three years. As of December 31, 2009, estimated share payouts for outstanding nonvested performance unit awards ranged from 110% to 120%.

We granted 28,113 performance units to certain officers in March 2009. These units will vest over a three-year performance period ending December 31, 2011 and are payable in HEP common units. The number of units actually earned will be based on the growth of distributions to limited partners over the performance period, and can range from 50% to 150% of the number of performance units issued. The fair value of these performance units is based on the grant date closing unit price of $23.30 and will apply to the number of units ultimately awarded.

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A summary of performance unit activity and changes during the year ended December 31, 2009 is presented below:

Performance Units	**Payable In Units**
Outstanding at January 1, 2009 (not vested)	36,971
Vesting and payment of units to recipients	(10,313)
Granted	28,113
Forfeited	
Outstanding at December 31, 2009 (not vested)	54,771

The fair value of performance units vested and transferred to recipients during the years ended December 31, 2009 and 2008 was $0.4 million and $0.1 million, respectively. There were no performance units that were vested and transferred prior to 2008. Based on the weighted average fair value at December 31, 2009 of $42.10, there was $0.7 million of total unrecognized compensation cost related to nonvested performance units. That cost is expected to be recognized over a weighted-average period of 1.5 years.

Note 8: Debt

Credit Agreement

We have a $300 million senior secured revolving Credit Agreement expiring in August 2011. The Credit Agreement is available to fund capital expenditures, acquisitions, and working capital and for general partnership purposes. In addition, the Credit Agreement is available to fund letters of credit up to a $50 million sub-limit and to fund distributions to unitholders up to a $20 million sub-limit. Advances under the Credit Agreement that are designated for working capital are classified as short-term liabilities. Other advances under the Credit Agreement, including advances used for the financing of capital projects, are classified as long-term liabilities. During the year ended December 31, 2009, we received advances totaling $239 million that were used as interim financing for our acquisitions and for capital projects and repaid $233 million, resulting in $6 million in net advances received. As of December 31, 2009, we had $206 million outstanding under the Credit Agreement.

Our obligations under the Credit Agreement are collateralized by substantially all of our assets. Indebtedness under the Credit Agreement is recourse to HEP Logistics Holdings, L.P., our general partner, and guaranteed by our wholly-owned subsidiaries. Any recourse to HEP Logistics Holdings, L.P. 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. We are required to reduce all working capital borrowings under the Credit Agreement to zero for a period of at least 15 consecutive days in each twelve-month period prior to the maturity date of the agreement. As of December 31, 2009, we had no working capital borrowings.

Indebtedness under the Credit Agreement bears interest, at our option, at either (a) the reference rate as announced by the administrative agent plus an applicable margin (ranging from 0.25% to 1.50%) or (b) at a rate equal to LIBOR plus an applicable margin (ranging from 1.00% to 2.50%). In each case, the applicable margin is based upon the ratio of our funded debt (as defined in the agreement) to EBITDA (earnings before interest, taxes, depreciation and amortization, as defined in the agreement). At December 31, 2009, we were subject to an applicable margin of 1.75%. We incur a commitment fee on the unused portion of the Credit Agreement at a rate ranging from 0.20% to 0.50% based upon the ratio of our funded debt to EBITDA for the four most recently completed fiscal quarters. At December 31, 2009, we are subject to a 0.30% commitment fee on the $94 million unused portion of the Credit Agreement. The agreement expires in August 2011. At that time, the agreement will terminate and all outstanding amounts thereunder will become due and payable.

The 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 and 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.

Additionally, the Credit Agreement contains certain provisions whereby the lenders may accelerate payment of outstanding debt under certain circumstances.

Senior Notes Due 2015

Our Senior Notes maturing March 1, 2015 are registered with the U.S. Securities and Exchange Commission (SEC) and bear interest at 6.25%. 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 Holdings, L.P., our general partner, and guaranteed by our wholly-owned subsidiaries. However, any recourse to HEP Logistics Holdings, L.P. would be limited to the extent of its assets, which other than its investment in us, are not significant.

Our contribution agreements with Alon and our purchase and contribution agreements with Holly with respect to the Intermediate Pipelines and the Crude Pipelines and Tankage Assets restrict us from selling pipelines and terminals acquired from Alon or Holly, as applicable, and from prepaying more than $30 million of the Senior Notes until 2015 and $171 million in borrowings for the purchase of the Crude Pipelines and Tankage Assets until 2018, subject to certain limited exceptions.

Long-term Debt

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

	December 31, 2009	December 31, 2008
	(In thousands)	
Credit Agreement	$ 206,000	$ 200,000
Senior Notes		
Principal	185,000	185,000
Unamortized discount	(1,964)	(2,344)
Unamortized premium dedesignated fair value hedge	1,791	2,137
	184,827	184,793
Total debt	390,827	384,793
Less net short-term borrowings under credit agreement		29,000
Total long-term debt	$ 390,827	$ 355,793

Interest Rate Risk Management

We use interest rate swaps (derivative instruments) to manage our exposure to interest rate risk. As of December 31, 2009, we have three interest rate swap contracts.

We have an interest rate swap that hedges our exposure to the cash flow risk caused by the effects of LIBOR changes on the $171 million Credit Agreement advance that we used to finance our purchase of the Crude Pipelines and Tankage Assets in February 2008. This interest rate swap effectively converts our $171 million LIBOR based debt to fixed rate debt having an interest rate of 3.74% plus an applicable margin, currently 1.75%, which equaled an effective interest rate of 5.49% as of December 31, 2009. The maturity date of this swap contract is February 28, 2013.

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 our $171 million 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 income. 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 our $171 million variable rate debt. Any ineffectiveness is reclassified from accumulated other comprehensive income to interest expense. As of December 31, 2009, we had no ineffectiveness on our cash flow hedge.

We also have an interest rate swap contract that effectively converts interest expense associated with $60 million of our 6.25% Senior Notes from a fixed to a variable rate (Variable Rate Swap). Under this swap contract, interest on the $60 million notional amount is computed using the three-month LIBOR plus a spread of 1.1575%, which equaled an effective interest rate of 1.41% as of December 31, 2009. The maturity date of this swap contract is March 1, 2015, matching the maturity of the Senior Notes.

We entered into an additional interest rate swap contract effective December 1, 2008, that effectively unwinds the effects of the Variable Rate Swap discussed above, converting $60 million of our hedged long-term debt back to fixed rate debt (Fixed Rate Swap). Under the Fixed Rate Swap, interest on a notional amount of $60 million is computed at a fixed rate of 3.59% versus three-month LIBOR which when added to the 1.1575% spread on the Variable Rate Swap results in an effective fixed interest rate of 4.75%. The maturity date of this swap contract is December 1, 2013.

Prior to the execution of our Fixed Rate Swap, the Variable Rate Swap was designated as a fair value hedge of $60 million in outstanding principal under the Senior Notes. We dedesignated this hedge in October 2008. At that time, the carrying balance of our Senior Notes included a $2.2 million premium due to the application of hedge accounting until the dedesignation date. This premium is being amortized as a reduction to interest expense over the remaining term of the Variable Rate Swap.

Our interest rate swaps not having a hedge designation are measured quarterly at fair value either as an asset or a liability in our Consolidated Balance Sheets with the offsetting fair value adjustment to interest expense. For the years ended December 31, 2009 and 2008, we recognized $0.2 million and $2.3 million, respectively, in interest expense attributable to fair value adjustments to our interest rate swaps.

We record interest expense equal to the variable rate payments under the swaps. Receipts under the swap agreements are recorded as a reduction of interest expense.

Additional information on our interest rate swaps as of December 31, 2009 is as follows:

Interest Rate Swaps	**Balance Sheet Location**	**Fair Value**	**Location of Offsetting Balance**	**Offsetting Amount**
		(In thousands)		
Asset				
Fixed-to-variable interest rate swap	Other assets	$ 2,294	Long-term debt	$ (1,791)(1)
$60 million of 6.25% Senior Notes			HEP partners equity	(1,942)(2)
			Interest expense	1,439(3)
		$ 2,294		$ (2,294)
Liability				
Cash flow hedge $171 million LIBOR based debt	Other long-term liabilities	$ (9,141)	Accumulated other comprehensive loss	$ 9,141

Variable-to-fixed interest rate swap $60 million	Other long-term liabilities	(2,555)	HEP partners equity Interest expense	4,166(2) (1,611)
		$ (11,696)		$ 11,696

(1) Represents unamortized balance of dedesignated hedge premium.

(2) Represents prior year charges to interest expense.

(3) Net of amortization of premium attributable to dedesignated hedge

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On January 29, 2010, we received notice from the counterparty that it is exercising its option to cancel the Variable Rate Swap on March 1, 2010, pursuant to the terms of the swap contract. We will receive a cancellation premium of $1.9 million.

Interest Expense and Other Debt Information

Interest expense consists of the following components:

	Years Ended December 31,		
	2009	**2008**	**2007**
		(In thousands)	
Interest on outstanding debt:			
Senior Notes, net of interest on interest rate swaps	$ 10,703	$ 10,454	$ 11,867
Credit Agreement, net of interest on interest rate swap	10,657	8,705	
Net change in fair value of interest rate swaps	175	2,282	
Net amortization of discount and deferred debt issuance costs	706	1,002	1,008
Commitment fees	268	327	414
Total interest incurred	22,509	22,770	13,289
Less capitalized interest	1,008	1,007	
Net interest expense	$ 21,501	$ 21,763	$ 13,289
Cash paid for interest (1)	$ 21,721	$ 12,464	$ 12,316

(1) Net of cash received under our interest rate swap agreements of $3.8 million for each of the years ended December 31, 2009, 2008 and 2007.

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, 2009, the minimum future rental commitments under operating leases having non-cancelable lease terms in excess of one year are as follows:

Year Ending December 31,	**$000 s**
2010	$ 6,264
2011	6,255

2012	6,261
2013	6,226
2014	6,225
Thereafter	16,415
Total	$ 47,646

Rental expense charged to operations was $7.1 million, $6.5 million and $6.1 million for the years ended December 31, 2009, 2008 and 2007, 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 from continuing operations are domestic revenues, of which over 90% are currently generated from our two largest customers: Holly and Alon. The major concentration of our petroleum product and crude oil pipeline system s revenues is derived from activities conducted in the southwest United States.

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

	Years Ended December 31,		
	2009	2008	2007
Holly	69%	78%	66%
Alon	26%	17%	22%

Note 11: Related Party Transactions

Holly and Alon Agreements

We serve Holly s refineries in New Mexico, Utah and Oklahoma under several long-term pipeline and terminal, tankage and throughput agreements.

In connection with our 2009 asset acquisitions, we entered into three new 15-year transportation agreements with Holly, each expiring in 2024. We entered into the Holly PTTA whereby Holly agreed to transport, throughput and load volumes of product via our logistics and storage assets acquired from Sinclair that are located at Holly s Tulsa Refinery. Additionally, we entered into the Holly RPA that relates to the Roadrunner Pipeline acquired from Holly in December 2009 and the Holly ETA that relates to the Tulsa loading racks acquired from Holly in August 2009.

In addition, we have the Holly PTA (expiring in 2019) that relates to the pipelines and terminals contributed to us at the time of our initial public offering in 2004, the Holly IPA (expiring in 2024) that relates to the Intermediate Pipelines acquired in 2005 and in June 2009, and the Holly CPTA (expiring in 2023) that relates to the Crude Pipelines and Tankage Assets acquired in 2008.

Under these agreements, Holly 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 will be adjusted each year at a percentage change based upon the change in the Producer Price Index (PPI) but will not decrease as a result of a decrease in the PPI. Under these agreements, the agreed upon tariff rates are adjusted each year on July 1 at a rate based upon the percentage change in the PPI or the Federal Energy Regulatory Commission (FERC) index, but with the exception of the Holly IPA, generally will not decrease as a result of a decrease in the PPI or FERC index. The FERC index is the change in the PPI plus a FERC adjustment factor that is reviewed periodically. Following our July 1, 2009 PPI rate adjustments, these agreements, including our new 2009 agreements with Holly, will result in minimum payments to us of $118.5 million for the twelve months ended June 30, 2010.

Additionally in February 2010, we entered into a pipeline systems operating agreement with Holly expiring in 2014 (the Holly Pipeline Operating Agreement). Under the Holly Pipeline Operating Agreement, effective December 1, 2009, we will operate certain tankage, pipelines, asphalt racks and terminal buildings owned by Holly for an annual management fee of $1.3 million.

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 results in a minimum level of annual revenue. The agreed upon tariff rates are increased or decreased annually at a rate equal to the percentage change in PPI, but not below the initial tariff rate. Following the March 1, 2009 PPI adjustment, Alon s total minimum commitment for the twelve months ending February 28, 2010 is $21.7 million.

If Holly or Alon fail to meet their 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. A shortfall payment under the Holly PTA, Holly IPA and Alon PTA may be applied as a credit in the following four quarters after minimum obligations are met.

We entered into an omnibus agreement with Holly in 2004 that we and Holly amended and restated several times in connection with our acquisitions from Holly in 2009 with the last amendment and restatement occurring on December 1, 2009 (the Third Restated Omnibus Agreement). Under certain provisions of the Third Restated Omnibus Agreement, we pay Holly an annual administrative fee for the provision by Holly or its affiliates of various general and administrative services to us, currently $2.3 million, for the provision by Holly 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 Holly. We also reimburse Holly and its affiliates for direct expenses they incur on our behalf.

Related party transactions with Holly are as follows:

- Pipeline, terminal and tankage revenues received from Holly were $101.4 million, $85 million and $61 million for the years ended December 31, 2009, 2008 and 2007, respectively. These amounts include revenues received under our long-term transportation agreements with Holly.
- Other revenues received from Holly for the year ended December 31, 2007 were $2.7 million related to our sale of inventory of accumulated terminal overages of refined product. These overages arose from net product gains at our terminals from the beginning of 2005 through the third quarter of 2007. In the fourth quarter of 2007, we amended our pipelines and terminals agreement with Holly to provide that, on a go-forward basis, such terminal overages of refined product belong to Holly.
- Holly charged general and administrative services under the Third Restated Omnibus Agreement of $2.3 million, $2.2 million and $2 million for the years ended December 31, 2009, 2008 and 2007, respectively.
- We reimbursed Holly for costs of employees supporting our operations of $17 million, $13.1 million and $8.5 million for the years ended December 31, 2009, 2008 and 2007, respectively.
- Holly reimbursed us $1.7 million and $0.3 million for certain costs paid on their behalf for the years ended December 31, 2009 and December 31, 2007, respectively.
- We paid Holly 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 $29.5 million, $25.6 million and $22.8 million for the years ended December 31, 2009, 2008 and 2007, respectively, to Holly as regular distributions on its common units, subordinated units and general partner interest, including general partner incentive distributions.
- Our accounts receivable from Holly was $14.1 million and $9.4 million at December 31, 2009 and 2008, respectively.
- Our accounts payable to Holly were $2.4 million and $2.2 million at December 31, 2009 and 2008, respectively.
- Holly failed to meet its minimum volume commitment for each of the eighteen quarters since inception of the Holly IPA. Through December 31, 2009, we have charged Holly $10.6 million for these shortfalls of which $0.7 million and $0.5 million is included in affiliate accounts receivable at December 31, 2009 and 2008, respectively.
- Our revenues for the years ended December 31, 2009, 2008 and 2007 include shortfalls billed under the Holly IPA of $2.4 million in 2008, $1.2 million in 2007 and $2.4 million in 2006, respectively, as Holly did not exceed its minimum volume commitment in any of the subsequent four quarters in 2009, 2008 and 2007. Deferred revenue in the consolidated balance sheets at December 31, 2009 and 2008, includes $3.6 million and $2.4 million, respectively, relating to the Holly IPA. It is possible that Holly may not exceed its minimum obligations under the Holly IPA to allow Holly to receive credit for any of the $3.6 million deferred at December 31, 2009.

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- We acquired the Roadrunner and Beeson Pipelines, Tulsa loading racks, a 16-inch intermediate pipeline and the Crude Pipelines and Tankage Assets from Holly in December 2009, August 2009, June 2009 and February 2008, respectively. See Note 3 for a description of these transactions.

Alon became a related party when it acquired all of our Class B subordinated units in connection with our acquisition of assets from them in February 2005.

Related party transactions with Alon are as follows:

- Pipeline and terminal revenues received from Alon were $30.8 million, $11.6 million and $21.8 million for the years ended December 31, 2009, 2008 and 2007, respectively, under the Alon PTA. Additionally, pipeline revenues received under a pipeline capacity lease agreement with Alon were $6.6 million, $7 million and $7.1 million for the years ended December 31, 2009, 2008 and 2007, respectively.
- We distributed $2.9 million, $2.8 million and $2.6 million for the years ended December 31, 2009, 2008 and 2007, respectively, to Alon for distributions on its Class B subordinated units.
- Our accounts receivable trade include receivable balances from Alon of $4 million and $2.5 million at December 31, 2009 and 2008, respectively.
- Our revenues for the years ended December 31, 2009 and 2008 include shortfalls billed under the Alon PTA of $13.3 million in 2008 and $2.6 million in 2007, respectively, as Alon did not exceed its minimum revenue obligation in any of the subsequent four quarters in 2009 and 2008. Deferred revenue in the consolidated balance sheets at December 31, 2009 and 2008 includes $4.8 million and $13.3 million, respectively, relating to the Alon PTA. It is possible that Alon may not exceed its minimum obligations under the Alon PTA to allow Alon to receive credit for any of the $4.8 million deferred at December 31, 2009.

Note 12: Partners Equity, Income Allocations and Cash Distributions

Holly currently holds 7,290,000 of our common units and the 2% general partner interest, which together constitutes a 34% ownership interest in us. In August 2009, all of the conditions necessary to end the subordination period for the 7,000,000 subordinated units owned by Holly were met and the units were converted into our common units on a one-for-one basis.

Currently, there are 937,500 of our Class B subordinated units that are outstanding and owned by Alon. The subordination period of these units extends until the first day of any quarter beginning after March 31, 2010, provided Alon is not in default with respect to payments due under its minimum volume commitments under the Alon PTA for each of the three consecutive, non-overlapping four-quarter periods immediately preceding such date. At the end of the subordination period, the Class B subordinated units will convert into our common units on a one-for-one basis. These subordinated units are not publicly traded.

Issuances of units

In connection with our December 1, 2009 acquisition of Sinclair s Tulsa logistics assets, 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 price.

In November 2009, we closed on a public offering of an additional 2,185,000 of our common units priced at $35.78 per unit, including 285,000 common units issued pursuant to the underwriters exercise of their over-allotment option. Aggregate net proceeds of $74.9 million were used to fund the cash portion of our December 1, 2009 asset acquisitions, to repay outstanding borrowings under the Credit Agreement and for general partnership purposes.

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

Concurrent with the 2009 common unit issuances described above, we received aggregate capital contributions of $3.8 million from our general partner during 2009 to maintain its 2% general partner interest.

As partial consideration for our purchase of the Crude Pipelines and Tankage Assets in 2008, we issued 217,497 of our common units having a fair value of $9 million to Holly. Also, Holly purchased an additional 2,503 of our common units for $0.1 million and HEP Logistics Holdings, L.P., our general partner, contributed $0.2 million as an additional capital contribution in order to maintain its 2% general partner interest.

Under our registration statement filed with the SEC using a shelf registration process, we currently have the ability to raise approximately $860 million through security offerings, 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 generally 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 attributable to HEP:

	2009	2008	2007
		(In thousands)	
General partner interest in net income	$ 1,210	$ 445	$ 737
General partner incentive distribution	6,737	3,468	2,429
Total general partner interest in net income attributable to HEP	$ 7,947	$ 3,913	$ 3,166

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. The Credit Agreement prohibits us from making cash distributions if any potential default or event of default, as defined in the Credit Agreement, occurs or would result from the cash distribution.

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. Working capital borrowings are generally borrowings that are made under the Credit Agreement and in all cases are used solely for working capital purposes or to pay distributions to partners.

We make distributions of available cash from operating surplus for any quarter during which we have outstanding subordinated units in the following manner: firstly, 98% to the 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; secondly, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period; thirdly, 98% to the subordinated unitholders, pro rata, and 2% to the general partner, until we distribute for each subordinated unit an amount equal to the minimum quarterly distribution for that quarter; and thereafter, cash in excess of the minimum quarterly distributions is distributed to the unitholders and the general partner based on the percentages below.

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

	Total Quarterly Distribution	Marginal Percentage Interest in Distributions	
	Target Amount	**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 27, 2010, we announced our cash distribution for the fourth quarter of 2009 of $0.805 per unit. The distribution is payable on all common, subordinated, and general partner units and will be paid February 12, 2010 to all unitholders of record on February 5, 2010.

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.

	2009	2008	2007
	(in thousands, except per unit data)		
General partner regular distribution	$ 1,356	$ 1,069	$ 946
General partner incentive distribution	6,737	3,468	2,429
Total general partner distribution	8,093	4,537	3,375
Limited partner distribution	59,725	49,085	45,685
Total regular quarterly cash distribution	$ 67,818	$ 53,622	$ 49,060
Cash distribution per unit applicable to limited partners	$ 3.16	$ 3.00	$ 2.835

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 equity since our regular quarterly distributions have exceeded our quarterly net income. Additionally, if the assets transferred to us upon our initial public offering in 2004, the intermediate pipelines purchased from Holly in 2005 and the assets purchased from Holly in 2009 had been acquired from third parties, our acquisition cost in excess of Holly s basis in the transferred assets of $160.4 million would have been recorded as increases to our properties and equipment and intangible assets instead of reductions to equity.

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Note 13: Quarterly Financial Data (Unaudited)
Summarized quarterly financial data is as follows:

	First	Second	Third	Fourth	Total
	(In thousands, except per unit data)				
Year ended December 31, 2009[1]					
Revenues	$ 29,332	$ 37,999	$ 40,805		